EUB

EPCOR Energy Services Inc.

2004 Regulated Rate Tariff
Part A: January 1, 2004, Interim Tariff

December 5, 2003

Alberta Energy and Utilities Board

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2004 Regulated Rate Tariff
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ALBERTA ENERGY AND UTILITIES BOARD
Decision 2003-087: EPCOR Energy Services Inc.
2004 Regulated Rate Tariff
Part A: January 1, 2004, Interim Tariff
Application No. 1306821

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ALBERTA ENERGY AND UTILITIES BOARD
Calgary Alberta

EPCOR ENERGY SERVICES INC.
2004 REGULATED RATE TARIFF
PART A: JANUARY 1, 2004, INTERIM TARIFF

Decision 2003-087
Application No. 1306820
File No. 1706-3

1 INTRODUCTION AND BACKGROUND

With the passage of the new *Electric Utilities Act*, SA 2003, c.E-5.1 (EUA), which came into force on June 1, 2003, the municipal electric distribution systems of the Cities of Edmonton and Calgary became subject to the jurisdiction of the Alberta Energy and Utilities Board (Board). In particular, the Board became the regulatory authority for EPCOR Distribution Inc. (EDI)[1] and ENMAX Power Corporation (EPC) for the purposes of approving distribution tariffs (DT) and regulated rate tariffs (RRT) to be effective January 1, 2004.[2].

The *Regulated Default Supply Regulation*, AR 168/2003 (*RDS Regulation*), required EDI and EPC to apply to the Board for approval of their RRTs on or before October 1, 2003.[3] The *RDS Regulation* requires the Board either to approve a final RRT for EDI and EPC to take effect on January 1, 2004, or to approve an interim RRT no later than November 30, 2003 to take effect on January 1, 2004.

Since January 1, 2001, EPCOR Energy Services Inc. (EESI) has provided regulated rate service (formerly regulated rate option or RRO service) in the EDI service area pursuant to an arrangement between EDI and EESI approved by Edmonton City Council. On October 10, 2003 EDI filed an arrangement with the Board that would allow EESI to continue to act as the regulated rate tariff provider in EDI's service area (Arrangement).[4] The Arrangement was approved by the Board in Decision 2003-085 in conjunction with EDI's 2004 interim DT.

As required by the *RDS Regulation*, on October 1, 2003, the Board received Application No. 1306820 (Application or RRT Application) from EESI seeking approval of its 2004 regulated rate tariff (RRT) in the EDI service area. The RRT approved by the Board for EESI will set out rates for RRT service, including energy and non-energy charges, as well as Terms and Conditions of Service (T&Cs) for all eligible customers as defined in the *RDS Regulation*.

On July 14, 2003, in anticipation of EESI's RRT Application, the Board issued a notice setting out a schedule to consider EESI's RRT and a number of other matters (Notice).[5] The Notice indicated that parties interested in EESI's RRT Application should register by August 15, 2003 and that parties not registering by that date would not be updated as to any changes to the schedule of the RRT Application.

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1 EDI owns and operates an electric distribution system in the City of Edmonton.
2 EUA, sections 102 and 103.
3 *DT Regulation*, section 4(1).
4 Application No. 1316786
5 An EDI 2004 Distribution Tariff (DT), an ENMAX Power Corporation (EPC) 2004 DT and an EPC 2004 RRT

Part of Application 1306820 is a negotiated settlement that deals with residential energy charges for the years 2004 and 2005 (Residential Settlement). EESI filed the Residential Settlement with the Board on October 9, 2003, and requested approval pursuant to section 134 of the EUA.

The Board established the following for the EESI RRT Application, including the Residential Settlement:

Filing of EESI RRT Application	October 01, 2003
Filing of EESI Residential Settlement	October 09, 2003
IRs to EESI on the RRT Application	October 10, 2003
IRs to EESI on Residential Settlement	October 16, 2003
IR Responses from EESI re RRT Application	October 20, 2003
IR Responses from EESI re RRT Residential Settlement	October 23, 2003
Interim Hearing	October 27, 2003
Oral Argument and Reply	October 30, 2003

EESI requested that if final approval of its entire RRT Application and Residential Settlement could not be issued by November 30, 2003, then the Board should give final approval to the Residential Settlement, which includes a final fixed charge for electric energy, and issue an interim approval for the other elements of EESI's RRT.

Under the terms of the *RDS Regulation* in force prior to November 4, 2003, only "rate classification customers"[6] (RCC) could be provided a hedged transition rate beyond the end of 2003. All other eligible customers ("non-rate classification customers" or NRCC) could only receive a flow-through rate as of January 1, 2004.

On November 4, 3003, the Government of Alberta announced that it intended to extend the availability of the transition rate to ***all*** eligible customers[7] through to June 30, 2006. On November 4, 2003, the Minister of Energy enacted the *Regulated Default Supply Amendment Regulation* by way of Ministerial Order 73/2003 (*RDS Amendment Regulation*). The effect of the *RDS Amendment Regulation* is to require an RRT provider to offer ***only*** a transition rate to all eligible customers until June 30, 2006, and to offer ***only*** a flow-through rate to all eligible customers after July 1, 2006.

On November 26, 2003, the Government of Alberta issued the *Regulated Default Supply Amendment Regulation (No. 2)* by way of Ministerial Order 80/2003 (*RDS Amendment Regulation No. 2*). Among other things, the *RDS Amendment Regulation No. 2* authorized the Board to extend the November 30, 2003 deadline prescribed in sections 3(2), 3(3)(a) and 3(4) of the *RDS Regulation* to no later than January 31, 2004. By way of letter dated November 27, 2003, the Board determined that it would extend the November 30, 2003 date specified in

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6 "Rate classification customer" is specifically defined in section 1(1)(e) of the *RDS Regulation*:
(e) "rate classification customer" means
i) a residential rate classification customer,
ii) a farm rate classification customer, or
iii) an irrigation rate classification customer,
as defined in a regulated rate tariff.

7 "eligible customer", as set out in section 1(1)(b) of the *RDS Regulation*, means a rate classification customer, and any other customer, if the owner's reasonable forecast of the customer's annual consumption of electric energy at a site is less than 250 megawatt hours of electric energy at that site.

sections 3(2), 3(3)(a) and 3(4) of the *RDS Regulation* to Friday December 5, 2003. In the Views of Parties in this Decision, any references to a required date of November 30, 2003 should now be considered as amended to read December 5, 2003.

Pursuant to the *RDS Amendment Regulation*, EESI filed a revised RRT Application on November 18, 2003 (Revised Application) which included a transition rate for eligible Non-Rate Classification Customers (NRCC) (i.e. the small commercial and lighting rate classes).

In the Revised Application EESI indicated that the RRT Application was amended by deleting Section 5.2 and as otherwise required such that the RRT Application no longer requests approval of the flow-through energy charges and the energy charge deferral account for NRCC. In the Revised Application EESI now requests final approval of an Energy Price Setting Plan for NRCC on or before November 30, 2003.

The Revised Application continues to seek approval, on or before November 30, 2003, of:

- the Residential Settlement and the energy charge applicable under the RRT service provided to residential rate class customers that is established for 2004 by the 2004-2005 Energy Price Setting Plan;
- the Regulated Rate Tariff Terms and Conditions (as amended); and,
- the interim non-energy charges as discussed in section 2.1 of the Application.

In order to satisfy the requirements of subparagraph 4(1)(c)(i) of the RDS Regulation, as amended, as they relate to NRCC, EESI proposed to implement a further 2004-2005 Energy Price Setting Plan.[8] EESI therefore sought approval, on or before November 30, 2003 of:

- the NRCC Plan;
- the approach to procuring energy and establishing the energy prices for NRCC that is described in the Amending Application;
- the Energy Charge Schedule for NRCC, a copy of which was attached as Attachment "3" to the Amending Application; and,
- a Credit Cost Factor on an interim refundable basis.

In a letter dated November 19, 2003 the Board provided notice of EESI's Revised Application and set out the following schedule that would allow the Board to issue a Decision by the legislated date of November 30, 2003:

Parties Written Comments for EESI	November 24, 2003
Parties Written Reply Comments for EESI	November 26, 2003
EESI Board Decision (on or before)	November 30, 2003

[8] NRCC Plan.

As noted above, the Board extended the November 30, 2003 date specified in sections 3(2), 3(3)(a) and 3(4) of the *RDS Regulation* to Friday December 5, 2003. The Board also indicated that it did not consider it necessary to re-open any of these proceedings and would issue this Decision on the basis of the record at that time.

For administrative purposes of this Decision, the Board considers the record to have closed on November 26, 2003. Parties participating in the proceedings are shown in Appendix 1 to this Decision.

In this Decision, the Board will deal with the fixed energy charge component and the return margin component of the RCC transition rate included in the Residential Settlement on a final basis. The Board will also deal with the fixed energy charge component of the NRCC transition rate on a final basis. Return margin for the NRCC transition rate will be dealt with on an interim basis. All other elements, of EESI's RRT to be effective January 1, 2004, including non-energy charges, will be dealt with by the Board in this Decision an interim basis.

2 RATE CLASSIFICATION CUSTOMERS (RCC) ENERGY RATES

2.1 Residential Settlement

EESI applied to the Board on August 1, 2003 for approval to initiate a negotiated settlement in the EDI service area for a 2004 and 2005 energy price setting plan for a RRT transition rate for its RCC (also sometimes referred to in this Decision as Residential RRT customers). EESI indicated that the following issues were expected to be resolved through the negotiation process:

- energy price setting methodology (e.g., hedged vs. a flow-through of the Alberta Pool price);
- the administration (billing) charge;
- return margin on customer bills payable to the Regulated Rate Provider; and
- term of agreement.

In Decision 2003-62, dated August 12, 2003, the Board approved EESI's application to commence negotiations. EESI advised potential participants of the settlement negotiations through an advertisement placed in the Edmonton daily newspapers in August, 2003. The advertisement advised interested parties to contact EESI by August 26, 2003 if they wished to express an interest to participate in the settlement negotiations or to obtain additional information. EESI received two replies to the advertisement. One individual did not respond to several phone messages that EESI subsequently left at his residence. The second individual expressed an interest in participating as an observer for the purpose of furthering her commodity-related education. EESI satisfied her interest by providing her with a copy of the amended RRT application filed with the Board on August 8, 2003 by EESI's sister company, EPCOR Energy Services (Alberta) Inc. (EESAI).

As directed by the Board, on August 27, 2003 EESI also provided notice of the settlement discussions to parties registered, by August 15, 2003, in the EDI/ENMAX tariff proceedings.[9]

[9] Decision 2003-62, p. 2.

EESI commenced settlement discussions with a meeting held on September 2, 2003. Representatives of EESI and the Consumers Coalition of Alberta (CCA) attended the meeting, as did a Board Observer. A second meeting was held on September 9, 2003 and was attended by representatives of EESI and the CCA, a representative of the City of Edmonton, an Independent Advisor[19] and the Board Observer. The third and final meeting occurred on September 15, 2003 at which EESI and the CCA, with the Board Observer in attendance, reached an agreement on the material aspects of the Residential Settlement and the 2004-2005 Plan.

EESI indicated that, in advance of the September 15, 2003 meeting, the City of Edmonton advised EESI that it would not be continuing its participation in the settlement discussions. A representative from the St. Michael's Extended Care Centre Society (St. Michael's), a member of the Care Center Group (CCG), also participated in the September 15, 2003 meeting.

EESI indicated that St. Michael's was not a signatory to the Residential Settlement and that at the time the Residential Settlement was filed, EESI and St. Michael's were negotiating a separate settlement agreement that could be implemented if: (i) the Board were to determine that St. Michael's is eligible for service under a RRT transition rate in 2004 or 2005; and (ii) the Board were to approve the Residential Settlement. EESI indicated that any agreement reached with St. Michael's would be filed with the Board for approval in due course. EESI indicated that any agreement would not affect in any way the energy charge applicable under the Residential Settlement.

The Residential Settlement includes an Energy Price Setting Plan (2004-2005 Plan) and a Consultation Agreement. The 2004-2005 Plan would establish a framework for procuring a supply of electric energy and establishing the RCC transition rate energy charge under EESI's RRT for 2004-2005. A Consultation Agreement between EESI and CCA would provide for ongoing consultations between EESI and the CCA in respect of implementing the 2004-2005 Plan and amending it from time to time in the future. Section 7 of the 2004-2005 Plan establishes a framework and process for these discussions.

A summary of the key elements of the Residential Settlement and the 2004-2005 Plan follows:

- EESI and the CCA agreed that, for the 2004 and 2005 calendar years, the energy price applicable under the EESI Residential RRT would be determined in accordance with the 2004-2005 Plan and the Energy Charge Schedule (Attachment "2" to the Residential Settlement reproduced in Appendix 2 to this Decision).
- EESI would include in the charges applicable to Residential RRT a 3.75% return margin calculated on the energy charge cost component of customer bills. EESI would also include in the charges applicable to Residential RRT customers a 3.25% return margin calculated on the Transmission and Distribution Charge cost components (T&D Charges) of customer bills. These return margins would be reduced by EESI's deemed corporate tax rate in each of 2004 and 2005. (The EESI return margin after the reduction for deemed corporate tax is 2.49% applicable to energy charges and 2.16% applicable to the T&D Charges.)

[19] The independent advisor was the same Independent Advisor as for the EESAI RRT.

- To the extent possible, all energy procured under the 2004-2005 Plan would be completed in conjunction with the procurement of electric energy to meet the obligations of EESAI to provide RRT service to eligible customers in non-EDI service areas.
- The monthly billing (administration) charge applicable to Residential RRT customers was expressly excluded from Residential Settlement and would be determined by the Board in its consideration of the EESI RRT Application.
- Notwithstanding anything to the contrary in the 2004-2005 Plan, the Parties could agree that all or part of the Super Peak Products for the first and fourth quarters of each of 2004 and 2005 would be acquired through the Power Pool. To the extent that all or a portion of these Super Peak Products were acquired through the Power Pool, the return margin applied to the energy charge for the portion of the Super Peak Products acquired through the Power Pool would be reduced by 75% from the level established under the Residential Settlement.
- The Aggregate Line Loss component of the energy charges applicable to the EESI Residential RRT for 2004 and 2005 would be set equal to line losses and Unaccounted For Energy calculations approved by the Board for EDI based upon the most recent 12 months of final Residential Settlement results received by EESI from EDI. EESI would update the Aggregate Line Loss component on a quarterly basis as part of the energy charge calculation.
- EESI would file with the Board, for acknowledgement only, quarterly updates to the energy charges resulting from the operation of the 2004-2005 Plan.

Certain information designated as commercially sensitive contained in Schedules B to F of the 2004-2005 Plan (Attachment 1 in Appendix 2 to this Decision) was not provided with the Residential Settlement (Commercially Sensitive Information). The Commercially Sensitive Information was, however, provided to the CCA.

EESI provided the following table, which illustrated forward energy prices at the time the Residential Settlement was filed, in accordance with section 10 of the Board's Revised Negotiated Settlement Guidelines. Table 1 below provides EESI's estimate of applicable energy charges for 2004 and 2005 assuming that the Residential Settlement and the 2004-2005 Plan were approved as filed. The actual 2003 energy charges were also provided for comparison purposes. EESI noted that the actual energy prices would be determined only if and when the 2004-2005 Plan was approved and implemented and would reflect the actual procurement costs prevailing at the relevant times.

Table 1. Residential Rate Class Actual 2003 and Estimated 2004 and 2005 Energy Prices ($/MWh)

EESI	Residential ($/MWh)
2003 Q1	58.25
2003 Q2	58.25
2003 Q3	59.25
2003 Q4	59.60
2004 Q1	53.28
2004 Q2	53.84
2004 Q3	53.81
2004 Q4	54.77
2005 Q1	49.24
2005 Q2	49.15
2005 Q3	49.69
2005 Q4	50.11

EESI also included forecast bill comparisons (Appendix 3 to this Decision) for EESI Residential RRT customers in the format requested by the Board in previous EESAI RRO/RRT proceedings. In addition to utilizing the energy charge estimates provided in Table 1, the bill comparisons included known changes to the EDI DT, the Alberta Electric System Operator's Tariff and associated rate riders.

2.2 Views of the Applicant

EESI submitted that the Residential Settlement should be treated as a unanimous settlement or at least one that is unopposed. EESI submitted that the Residential Settlement meets the criteria identified in section 12.5 of the Board's Negotiated Settlement Guidelines (IL 98-04 Revised).

EESI reiterated its request that the Residential Settlement be approved on an expedited basis since EESI/EESAI had already begun purchasing energy for RRT customers.

EESI noted that the RCC return margin[11] is established under the Residential Settlement and requested that it be approved by the Board. The Residential Settlement also stipulates that: (i) it is contingent on the Board accepting all of its provisions as contemplated in section 135 of the Act; and (ii) it will be null and void if the Board rejects it *in whole or in part*.[12]

EESI submitted that AE was mistaken by asserting that ". . . by choosing to amend this application, EESI has reopened this proceeding".[13] EESI submitted that the Revised Application clearly identified the amendments that were being made to the RRT Application and expressly stated that EESI continues to seek final approval of the Residential Settlement pertaining to RCC. EESI submitted that AE had also, apparently, overlooked the fact that the Board cannot approve only part of the Residential Settlement; which would be the effect of granting only interim approval of the RCC return margin.

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11 Paragraphs 1 a) and b) of the RCC Plan Settlement Agreement contemplate the same return margins as described in the previous footnote.

12 RCC Plan Settlement Agreement, s. 7 [emphasis added].

13 ATCO Electric Submission, p. 1.

Accordingly, EESI submitted that the AE position concerning the RCC return margin must be rejected.

2.3 Views of the Interveners

AE

AE was opposed to the approval of the return margin for the RCC RRT on other than an interim refundable basis. AE submitted that with the release of the *RDS Amendment Regulation,* the Government of Alberta had significantly changed the legislative framework under which the RRT is to be provided. AE noted that Section 6 of the *RDS Amendment Regulation*, which amends Section 5 of the *RDS Regulation* now requires the Board to approve the financial arrangements proposed by the RRT provider to ensure that the procurement risk of acquisition remains with the RRT provider. AE submitted that this amendment significantly increases the risk to the RRT provider, and under such changed circumstances, the Board has no alternative but to conduct a review of the requested return margin to ensure that the resulting tariff is just and reasonable, and in the public interest.

AE noted that the record for the original EESI Application has closed. AE submitted that by choosing to amend the RRT Application, EESI had reopened the proceeding. Therefore, AE believed that the Board's consideration of the return margin should not be limited to the return margin for NRCC customers, but instead, the return margin for all EESI RRT customers.

CCA

The CCA confirmed its support for the Residential Settlement and urged the Board to approve the Application.

CCG

CCG confirmed that it was not opposed to the Residential Settlement. CCG also indicated that it did not think that the scope of the Residential Settlement should be expanded to include any customer other than small residential rate class customers. CCG took the position that a separate settlement should be negotiated for the customers that it represented.

2.4 Views of the Board

While the Residential Settlement and 2004-2005 Plan are the first that the Board has dealt with for EESI, the Board has significant experience in the approval of similar settlements and plans for EESAI. Those plans were agreed to between EESAI and interested parties that included the CCA (the Consultation Parties). The Board has approved similar plans for EESAI for 2001,[14] 2002,[15] 2003[16] and 2004-2005.

[14] In Decision 2000-74
[15] In Decision 2001-87
[16] In Decision 2002-112

The most recent EESAI plan, for the 2004-2005 period, was approved in Decision 2003-074 dated October 7, 2003. In reaching its findings in that Decision, the Board heard *in camera* confidential information contained in Schedules B to F to EESAI's 2004-2005 Plan because EESAI and the Consultation Parties considered the information to be commercially sensitive. In Decision 2003-074, after considering all the evidence, including that heard *in camera,* the Board approved the EESAI 2004-2005 Plan with following comments:

> The Board believes that EESAI could enhance communication with its RRT customers. In that respect, the Board expects EESAI to provide customers with forward pricing information and an accurate explanation of all of the charges on the customer's monthly bill. The Board considers that EESAI should review all areas of its website for accuracy.
>
> In addition to providing information to customers, the Board directs EESAI to continue to file all quarterly RRT rate charges that result from the implementation of the 2004-2005 Plan as a Filing for Acknowledgement only, as was already done pursuant to Decision 2002-112, with respect to the 2003 Plan.
>
> Finally, the Board is not convinced that all the information in Schedules B to F of the 2004 and 2005 Energy Price Setting Plan was commercially sensitive. The Board would expect parties to a Settlement Agreement to disclose as much information as possible to enable non-participants to the negotiations and customers to get a better general understanding of the Agreement.

Given the timing of the EESI Residential Settlement, the Board does not consider that it would be reasonable to expect EESI to respond to the Board's disclosure concerns raised in Decision 2003-074. However, the Board considers that EESI should take those concerns into account in any future filing of a revised energy pricing plan under the Residential Settlement.

Furthermore, since the hedged energy for the 2004-2005 EESAI and EESI RRTs is to be procured at the same time, this division of the Board finds comfort in the fact that that the confidential aspects of the EESAI plan were reviewed by the division of the Board that issued Decision 2003-074 without any other concerns being raised by that division.

The 2004-2005 Energy Price Setting Plans specify the minimum amount and type of electricity contracts that EESI and EESAI must purchase in the open wholesale market. Under the Plans, EESAI and EESI are responsible for all risk due to volume differences between forecast and actual RRT consumption under their respective Plans. No fees are payable for entrance or exit from the RRTs. EESAI and EESI earn a return margin to compensate them for providing RRT service and for the risk each assumes under its respective Plan.

The Board recognizes that some differences exist between the EESI and EESAI settlements, including the effect of the tax-exempt status on the return margins allowed for EESI and the different level of the return margin on the delivery charges for EESI. However, the Board takes comfort from the fact that the CCA's participation in each settlement will likely ensure that the resulting margins were appropriate under the specific circumstances of each settlement.

The Board also notes EESI's uncontested evidence that the introduction of the proposed Volume and Bad Debt Deferral Accounts would not disturb the return margin that was negotiated for EESI's RRT. The Residential Settlement included a provision that the monthly billing (administration) charge applicable to Residential RCC was expressly excluded. The Board

considers that the Volume and Bad Debt Deferral Accounts impact only the monthly billing charge. Accordingly, the Board considers that its approval or denial of the Volume and Bad Debt Deferral Accounts in this Decision should not affect the Residential Settlement.

The Board notes that CCA executed the Residential Settlement and supported it at the Hearing. CCG appeared at the hearing and indicated that it was not opposed to the Residential Settlement and did not think that its scope should be expanded to include any customers other than small residential RCC. In circumstances like this, where the Board is presented with an unopposed negotiated settlement, the Board has held that it will treat the settlement as if it were a unanimous settlement.[17] This approach is now reflected in Section 12.5 of the Board's Revised Negotiated Settlement Guidelines.

Accordingly, the Board will apply the two-fold test established in Decision 2000-85 dated December 22, 2000. The two criteria used in that Decision, which the Board will address in the context of this Residential Settlement, are:

(1) Whether EESI's Residential Settlement process was fair and in accordance with the Board's Negotiated Settlement Guidelines (IL98-04 Revised), and

(2) Whether any aspect of the EESI Residential Settlement is patently contrary to the public interest.

Fairness of the Settlement Process

As noted above, the first question for the Board is whether EESI's Residential Settlement process was fair and in accordance with the Board's Negotiated Settlement Guidelines. In particular, the Board considers that a settlement is fair and in accordance with the guidelines if proper notice has been provided, due process has been provided to the participants by allowing for meaningful participation in the process including the funding of interveners' participation, Board staff has participated as an observer in the discussions, and all parties expressing a significant interest have signed off on the settlement.

The Board is satisfied that proper notice was provided. In addition the Board is satisfied that EESI responded appropriately to all parties that responded to the Notice.

EESI and the CCA met on several occasions to reach an agreement. A Board Observer attended all meetings. EESI and the CCA retained an Independent Advisor who participated in the meetings. The Board Observer did not advise the Board of any concerns related to the negotiated settlement process. The Board considers that the evidence confirms that there was meaningful participation in the settlement process by the CCA.

The Board also notes the view of the CCA, who represented the interest of residential customers, that the Residential Settlement should be approved. The CCA is well known to the Board with a long record of representing the residents of Alberta.

The Board is satisfied that the negotiation process led to an agreement that is fair and reasonable has a well-substantiated rational basis and is complete and adequate to support the application.

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[17] Decision 2002-064, *ESBI Alberta Ltd., 2002 Tariff Application & Negotiated Residential Settlement* (July 16, 2002), page 15.

From the foregoing, the Board concludes that all parties had the opportunity to participate in the negotiation process in a meaningful manner.

The Board is satisfied that the Residential Settlement was reached fairly and in accordance with the Board's Negotiated Settlement Guidelines.

Public Interest

The second question for the Board is whether the Residential Settlement contains elements that could produce rates that are not just and reasonable. The Board considers that the expression of support from the CCA is of considerable comfort to the Board in assessing the justness and reasonableness of the resulting tariff. The Board considers the CCA to be experienced and knowledgeable due to its participation in several prior EESAI energy pricing settlements.

With respect to energy price impacts in 2004 and 2005, the Board notes that EESI provided information on forward electric energy prices and comparison of customer bills (Appendix 3 to this Decision), which indicated that customer energy charges in 2004 and 2005 are likely to be more favorable than current and previous charges.

According to the estimates set out earlier in Table 1, overall energy rates for an average residential customer were expected to drop by about 8.3% in 2004. A further drop of about 8.1% is expected from 2004 to 2005. The Board notes that these energy prices are estimates and that actual energy prices may be higher or lower than the energy prices outlined in Table 1.

Further, in Decision 2003-074, the Board indicated that:

> Because of the confidentiality safeguards that were put in place, the Board was able to examine all aspects of the 2004 and 2005 Plan. In addition, the Board was able to get the Consultation Parties' and the Independent Advisor's views with respect to the design of the EESAI's price hedging strategy and the protocol for acquiring the price-hedging products in the 2004 and 2005 energy supply portfolio. This evidence enables the Board to accept that the applied-for 2004 and 2005 Plan represents a viable method of establishing the energy charges for EESAI's RRT customers in 2004 and 2005 and also represents a prudent balance between price stability and energy costs.[18]

As noted earlier, since the hedged energy for the EESAI and EESI RRTs is to be procured at the same time, this division of the Board finds comfort in the fact that that the confidential aspects of the EESAI Plan were reviewed by the division of the Board that issued Decision 2003-074 approving the EESAI plan without any other concerns being raised.

The Board notes that the proposed RCC Plan sets out a "buy as you go approach" whereby one-year product, quarterly product and monthly (peak, off-peak, on peak and super peak) product are utilized to hedge the EESI RCC load requirements throughout the duration of the Plan. The Board notes that, with the exception of the super peak product discussed below, EESI RCC customers are fully hedged within any given month since EESI takes all hourly volume and price risk within the month. The Board considers that this approach eliminates the need for any

[18] Decision 2003-074, page 12.

retrospective price adjustments with respect to a given month since all procurement risk during a month remains with EESI.

To reduce the frequency of price adjustments from monthly to quarterly, EESI forecasts the price of hedges that will be bought during a given quarter for use during that quarter. Under the Plan, any differences between the forecast and actual market price of hedges purchased during a given quarter for use during that quarter are recovered from customers during the following quarter. The Board notes that, although customers are exposed to price changes in monthly and quarterly product as these products are purchased throughout the year, price adjustments only occur quarterly. The Board considers that this is a reasonable method of reducing the frequency of price adjustments to customers.

The Board also notes that, pursuant to the proposed RCC Plan, EESI may procure super peak product from the power pool at power pool prices during certain times of the year if customers agree to do so at that time. The Board considers that this option in the Plan, if implemented, would transfer hourly pool price risk to customers for a small portion of RCC load. Recognizing that such exposure to hourly pool price is only an option in the Plan, that the option can only be invoked during part of the year, and that the option can only be invoked with the approval of customers, the Board does not consider the degree of pool price risk which could be transferred to customers under the Plan to be material.

Having considered all of the evidence and argument, the Board is of the view that the 2004-2005 Plan will result in fair and reasonable final energy charges for EESI's RRT customers in 2004 and 2005. The Board considers that prudent and reasonable costs will be paid by EESI for electric energy if the framework set out in the 2004 -2005 Plan for acquiring price-hedging products is followed.

Further, having considered the terms of the Residential Settlement in light of the requirements of the amended *RDS Regulation* and the Board's Negotiated Settlement Guidelines, the Board finds that the Residential Settlement will result in an appropriate transition rate for EESI's RCC for 2004 and 2005.

The Board is satisfied that the proposed Residential Settlement will result in a fixed energy charge that is just and reasonable and in the public interest. Accordingly, the Board approves the fixed energy charge (including margin) that will result from the RCC 2004-2005 price setting plan on a final basis.

The Board notes that EESAI was directed in Decision 2001-112 to file with the Board, for acknowledgement only, quarterly updates to the energy charges resulting from the operation of the EESAI RRT Energy Plan. The Board notes that EESI is prepared to follow the same filing requirements with respect to the RCC 2004-2005 Plan. The Board agrees with EESI that this is appropriate.

Accordingly, the Board directs EESI to file with the Board all quarterly RCC rate charges and the non-confidential calculations behind their determination that result from the implementation of the RCC 2004-2005 Plan, as a Filing for Acknowledgement. As a result, the Board will then have the current RCC rate charges on file to provide to any customer requesting this information. Further, to provide pricing information to customers as soon as possible, the Board considers that EESI should post each RCC rate class's quarterly energy price change to its website as soon as the new quarterly prices are available.

3 NON-RATE CLASSIFICATION CUSTOMERS (NRCC) ENERGY RATES

3.1 Introduction

In its Revised Application, EESI proposed to implement a further 2004-2005 Energy Price Setting Plan for NRCC (the NRCC 2004-2005 Plan). A copy of the NRCC 2004-2005 Plan (excluding the confidential portions thereof) was attached as Attachment "2" to the Revised Application letter (Appendix 4 to the Decision).

In its Revised Application, EESI requested that the Board approve, on or before November 30, 2003:

- the NRCC 2004-2005 Plan;
- the approach to procuring energy and establishing the energy prices for NRCC that is described below;
- the Energy Charge Schedule for NRCC (NRCC Energy Charge Schedule) (included in Appendix 4 to this Decision); and
- the Credit Cost Factor that is described below, on an interim refundable basis.

EESI indicated that NRCC 2004-2005 Plan is, in almost all respects, the same as the RCC Plan. The only material difference between the Plans concerns the proposed process to approve the load forecast volumes and the addition of the credit cost recovery component.

EESI proposed that the Public Institutional Consumers of Alberta (PICA) approve the load forecast volumes required for the operation of the Plan. EESI noted that PICA has had extensive energy procurement experience through its involvement as one of the Consultation Parties in EESAI Energy Price Setting Plans. EESI and PICA signed a consultation agreement on November 24, 2003, wherein PICA will approve volumes for the NRCC. EESI also indicated that an expert in energy markets would be retained to serve in the role of independent advisor to aid in the execution of the NRCC 2004-2005 Plan.

EESI proposed that the charges applicable to NRCC include a 3.75% return margin calculated on the energy charge cost component of NRCC bills and a 3.25% return margin calculated on the T&D Charges components of customer bills. These return margins would be reduced by EESI's deemed corporate tax rate in each of 2004 and 2005. If EESI's deemed corporate tax rate changes for any reason, EESI indicated that it would make the necessary adjustment to the return margin. EESI acknowledged that its request was that the return margins be approved on an interim basis by November 30, 2003 and finalized later.[19]

[19] BR-EESI-26(a)

EESI indicated that, notwithstanding anything to the contrary in the NRCC 2004-2005 Plan, EESI and PICA may agree that all or part of the Super Peak Products for the first and fourth quarters of each of 2004 and 2005 should be acquired through the Power Pool. To the extent that all or a portion of such Super Peak Products are acquired through the Power Pool, the return margin applied to the energy charge for the portion of the Super Peak Products acquired through the Power Pool would be reduced by 75% from the level established under the Settlement Agreement.

EESI and PICA may also agree to replace certain yearly or monthly products with longer duration products (e.g., replace Peak Product with Base Product) if certain price ratios are exceeded during procurement sessions. Any differences between the acquisition price and the deemed sale price of volumes in the shoulder or off-peak hours associated with the replacement would be factored into the calculation of the energy charge. EESI noted that a similar mechanism is also included in the RCC Plan.

The Aggregate Line Loss component of the energy charges applicable to the NRCC for 2004 and 2005 would be calculated on the basis of the most recent 12 months of final settlement results received by EESI from EDI. EESI proposed to update the Aggregate Line Loss component on a quarterly basis as part of the energy charge calculation.

EESI indicated that it would file with the Board, for acknowledgement only, quarterly updates to the energy charges resulting from the operation of the NRCC 2004-2005 Plan as well as the Price Schedules that reflect those energy charges.

EESI indicated that it would incur incremental costs associated with posting credit with counter-parties for the purpose of procuring wholesale products under the NRCC 2004-2005 Plan. EESI forecasted that the cost of these prudential requirements would be equal to the product of 1.5% and 28% of the actual total costs of products procured under the NRCC 2004-2005 Plan. Currently, prudential requirements are expected to cover a 28% fluctuation in market prices and this provides the basis for using 28% of the procurement costs in determining the cost of prudential requirements. EESI proposed including these costs in the energy charge through a scaling factor (Credit Cost Factor) of 1.0042.

EESI requested that the Credit Cost Factor be approved on an interim refundable basis since EESI recognized that the concept of including the credit costs associated with the procurement of wholesale products had not been tested before the Board.

The 2004 and 2005 energy charges shown in Table 2 were calculated on the basis of current forward prices and estimated ratios of on-peak and on-super-peak to base prices. EESI noted that the actual energy prices would be determined only if and when the 2004-2005 Plan were approved and implemented and would reflect the actual procurement costs prevailing at the relevant times.

Table 2. Non-Residential Rate Class Actual 2003 and Estimated 2004 and 2005 Energy Prices ($/MWh)

$MWh	Small Commercial	Lighting
2003 Q1	58.25	38.33
2003 Q2	58.25	38.33
2003 Q3	58.49	37.04
2003 Q4	59.63	50.12
2004 Q1	55.66	47.42
2004 Q2	53.27	33.84
2004 Q3	53.63	36.41
2004 Q4	53.65	43.04
2005 Q1	49.35	41.94
2005 Q2	49.36	30.13
2005 Q3	49.86	33.97
2005 Q4	50.27	40.23

EESI also included forecast bill comparisons (Appendix 5 to this Decision) for EESI NRCC in the format requested by the Board in previous EESAI RRO/RRT proceedings. In addition to utilizing the energy charge estimates provided in Table 2, the bill comparisons included known changes to the EDI DT, the AESO Tariff and associated rate riders.

3.2 Views of the Applicant

EESI did not oppose the Board approving the NRCC return margin and the Credit Cost Factor on an interim refundable basis.

EESI submitted that the recommendations of the CCG, that the EESI NRCC Plan should be approved on an interim basis for no longer than one year (and preferably 6 months if practical) should be rejected.

EESI submitted that it was neither practical nor appropriate to "simplify" the NRCC plan as suggested by CCG. EESI also submitted that the NRCC Plan has evolved over the last three years and "simplification" may result in less effective hedges for customers. EESI did not share the apparent concern of the CCA that a single procurement pool could result in "cross-subsidization" among groups of customers. A single procurement pool would simply eliminate the potential for price differences arising from the timing of the hedge procurement.

EESI submitted that, if there is agreement among the Consultation Parties,[20] then EESI will pool the acquired hedges to arrive at a single on-peak and off-peak energy price. If there is no such agreement, then EESI would: (i) allocate hedges purchased up to November 14, 2003 to RCC; (ii) allocate hedges purchased after November 14, 2003 to both RCC and NRCC until the RCC hedge portfolio is completed; and, (iii) then procure solely on behalf of NRCC until the NRCC hedge portfolio is completed.[21] EESI requested that the Board approve the proposed approach to energy procurement on a final basis with EESI being permitted to pool the acquired hedges to arrive at a single on-peak and off-peak energy price if the Consultation Parties agree to pooling.

[20] Meaning, in this context, CCA, PICA and possibly CCG.
[21] Exhibit 003-213, PICA-EESI-2 a).

EESI did not object to the Board approving the line loss factor set out in the NRCC Energy Charge Schedule on an interim refundable basis. However, EESI submitted that the pool trading charge should be approved on a final basis in this proceeding.

3.3 Views of the Interveners

AE

AE was opposed to the approval of the return margin for the NRCC RRT on other than an interim refundable basis. With the release of the *RDS Amendment Regulation,* the Government of Alberta has significantly changed the legislative framework under which the RRT is to be provided. AE noted that Section 5 of the *Regulation* now requires the Board to approve the financial arrangements proposed by the RRT provider to ensure that the procurement risk of acquisition remains with the RRT provider. AE submitted that this amendment significantly increases the risk to the RRT provider, and under such changed circumstances, the Board has no alternative but to conduct a review of the requested return margin to ensure that the resulting tariff is just and reasonable, and in the public interest.

CCA

The CCA supported the comments made by PICA with the exception of those regarding the use of separate pools for RCC and NRCC energy. The CCA submitted that separate pools are the appropriate treatment for the RCC and NRCC RRT energy plans.

The CCA believed differences in price arising from having two procurement pools and two energy prices will prevent any material cross-subsidization to one group from any other group of customers. Prevention of cross subsidization is important enough to warrant the maintenance of two separate pools.

The CCA was open to the use of a single pool should the price differences between the pools be immaterial. The materiality threshold must be ultimately decided by the Board but the CCA considered a change of more than $0.0025/kWh as clearly having material consequences to customer bills.

CCG

The CCG supported EESI's proposal to have separate RCC and NRCC energy portfolios. The CCG submitted that there should be two pools to ensure no cross-subsidization between RCC and NRCC. Further, CCG considered that the use of two pools may simplify the determination of the correct energy price for each customer group. The CCG also submitted that the energy for multi-unit residences should be included with the portfolio for NRCC regardless of whether multi-unit residences are considered RCC. The CCG noted that it wished to be a consultation party, along with PICA, to the NRCC 2004-2005 Plan.

The CCG supported the approval of EESI's NRCC proposed return margin on an interim basis only. The CCG submitted that there was no basis for concluding that EESI's NRCC margins are appropriate for customers who consume significantly more energy than single-unit residences.

The CCG also proposed that the Credit Cost Factor be set to zero on an interim basis.

The CCG proposed that the two energy price setting plans (for the RCC and the NRCC) be approved on an interim basis for no longer than one year, preferably 6 months if practical. The CCG indicated that it had not had sufficient time to absorb the details of the plans, and had still not determined which of these plans would apply to the residences of the CCG.

The CCG was not convinced that the energy price setting plan (whichever would apply to the CCG) needed to be as complex as it is, especially with respect to customers who have time of use meters. The CCG wished to explore the possibility of simplifications wherever practicable.

The CCG submitted that a "fallback" energy price was necessary to apply effective January 1, 2004 in the event that the Consultation Parties do not agree to the NRCC energy price setting plan. The CCG suggested that the Board approve a fallback price of 5.161cents per kWh to be effective January 1, 2004. The CCG's proposed fallback price is the energy price proposed in the revised RRT application of ENMAX, which CCG understood to be the volume weighted price resulting from proposals that were received on November 18, 2003.

The EECG requested that owners or their designated service providers consider a sub-class of a rate category that would include those entitled to life-line rates. If such a tariff could be established, the extent to which the provincial government might subsidize any increases over the transition period could be identified.

PICA

PICA did not oppose approval of the NRCC 2004-2005 Plan. PICA considered that certain components, namely the return margin, line losses and pool trading charges require further testing and review and should only be approved on an interim refundable basis. PICA also submitted that the proposed credit cost factor should not be approved at all at this time and should be deferred for consideration as part of the final proceeding.

PICA submitted that, while there may be minor impacts to either RCC or NRCC, the use of two pools added an unnecessary level of complication and confusion for customers. There may also be efficiencies gained through the use of a single pool, helping to offset any differences in prices and/or gain or loss from having two procurement pools and two energy prices.

Further, the use of a uniform energy charge/kWh for RCC and NRCC may eliminate unnecessary confusion and controversy differing prices may create. Although PICA recognized that the end energy price will differ between customers based on load, line losses and similar factors, there was no clear reason to support the difference in the fixed energy price.

PICA supported use of a consultative process to determine the appropriateness of a two pool model (i.e. RCC and NRCC pools) for calculation of the energy charge. PICA considered that if agreement was not possible, the issue should be dealt with in the final proceeding.

3.4 Views of the Board

The Board notes that the proposed NRCC 2004-2005 Plan sets out a "buy as you go approach" whereby one-year product, quarterly product and monthly (peak, off-peak, on peak and super peak) product are utilized to hedge the EESI NRCC load requirements throughout the duration of the Plan. The Board notes that with the exception of the super peak product discussed below, EESI NRCC customers are fully hedged within any given month since EESI takes all hourly volume and price risk within the month. The Board considers that this approach eliminates the need for any retrospective price adjustments with respect to a given month since all procurement risk during a month remains with EESI.

To reduce the frequency of price adjustments from monthly to quarterly, EESI forecasts the price of hedges that will be bought during a given quarter for use during that quarter. Under the Plan, any differences between the forecast and actual market price of hedges purchased during a given quarter for use during that quarter are recovered from customers during the following quarter. The Board notes that, although customers are exposed to price changes in monthly and quarterly product as these products are purchased throughout the year, price adjustments only occur quarterly. The Board considers that this is a reasonable method of reducing the frequency of price adjustments to customers.

The Board also notes that, pursuant to the proposed NRCC Plan, EESI may procure super peak product from the power pool at power pool prices during certain times of the year if customers agree to do so at that time. The Board considers that this option in the Plan, if implemented, would transfer hourly pool price risk to customers for a small portion of NRCC load. Recognizing that such exposure to hourly pool price is only an option in the Plan, that the option can only be invoked during part of the year, and that the option can only be invoked with the approval of customers, the Board does not consider the degree of pool price risk which could be transferred to customers under the Plan to be material.

Having considered all of the evidence and argument, the Board is of the view that the NRCC 2004-2005 Plan will result in fair and reasonable final energy charges for EESI's NRCC customers in 2004 and 2005. The Board considers that prudent and reasonable costs will be paid by EESI for electric energy if the framework set out in the NRCC 2004 -2005 Plan for acquiring price-hedging products is followed.

Further, having considered the terms of the NRCC 2004-2005 Plan in light of the requirements of the amended *RDS Regulation*, the Board finds that the NRCC 2004-2005 Plan will result in an appropriate transition rate (before margin) for EESI's NRCC for 2004 and 2005.

The Board is satisfied that the proposed NRCC 2004-2005 Plan will result in a fixed energy charge (before margin) that is just and reasonable and in the public interest. Accordingly, the Board approves the fixed energy charge (before margin) that will result from the NRCC 2004-2005 Plan on a final basis. The Board also agrees that the requested return margin for the EESI NRCC should be approved on an interim refundable basis.

Since EESI's proposed Credit Cost Factor is a new and untested concept, the Board considers that the Credit Cost Factor should only be approved on an interim refundable basis.

The Board notes EESI's submission that, if there were agreement among the Consultation Parties, EESI would pool the acquired hedges to arrive at a single on-peak and off-peak energy price for RCC and NRCC. The Board further notes that EESI submitted that it was prepared to facilitate discussions of the pooling issue among the Consultation Parties. Accordingly, the Board considers it more appropriate that the decision respecting pooling of RCC and NRCC energy portfolios should be deferred until the final proceeding, in order to provide some time for EESI to facilitate discussions among the parties.

Accordingly, the Board directs EESI to facilitate discussions among the Consultation Parties to determine if agreement can be reached respecting the pooling of energy for RCC and NRCC. The Board further directs EESI to provide a report to the Board on or before February 13, 2004 summarizing the positions of parties respecting the above portfolio pooling issues. The Board will then deal with any remaining issues at the EESI final proceedings.

The Board notes PICA's concerns about line losses and EESI's agreement that the proposed methodology for determining the line loss factor could be examined in the final proceeding. For this reason the Board considers it appropriate to approve the proposed EESI line loss methodology on an interim refundable basis.

The Board also notes that PICA requested that the Board approve the proposed Pool Trading Charges on an interim refundable basis, pending final review in the March 2004 proceeding. However, the Board notes that the formula for the energy charge includes a flow-through of the Pool Trading Charges. As a result, the Board considers it appropriate to approve the component of the energy charge formula, which involves a flow-through of the actual Pool Trading Charges on a final basis.

For the same reasons given above in relation to the RCC 2004-2005 Plan, the Board directs EESI to file with the Board all quarterly NRCC rate charges and the non-confidential calculations behind their determination that result from the implementation of the NRCC 2004-2005 Plan, as a Filing for Acknowledgement. As a result, the Board will then have the current NRCC rate charges on file to provide to any customer requesting this information. Further, to provide pricing information to customers as soon as possible, the Board considers that EESI should post each NRCC rate class's quarterly energy price change to its website as soon as the new quarterly prices are available.

4 RCC AND NRCC NON-ENERGY RATES

4.1 Introduction

EESI proposed to continue its existing administrative non-energy charges for each rate classification on an interim basis. EESI's proposed non-energy charges are set out in Schedule A of this Decision.

4.2 Views of the Applicant

In the Revised Application, EESI indicated that the amendments to the *RDS Regulation* were expected to result in adjustments to various non-energy costs, including those related to hedging implementation and information technology. EESI noted that the cost changes did not affect the interim non-energy charges for which EESI has requested approval. EESI indicated that it would file appropriate amendments respecting the final non-energy charges in due course.

4.3 Views of the Interveners

No interveners opposed the continuation of existing non-energy charges on an interim basis.

4.4 Views of the Board

The Board notes that no party objected to EESI's proposal to continue its existing administrative non-energy charges for each rate classification on an interim basis. The charges would be changed as required after the Board's final determination of 2004 administrative non-energy charges. The Board considers that this approach will provide the greatest degree of stability to RRT customers.

Therefore, the Board accepts EESI's proposal to continue its existing administrative non-energy charges for each rate classification on an interim refundable basis.

5 RCC AND NRCC NON-ENERGY DEFERRAL ACCOUNTS

EESI requested interim approval for the following three non-energy deferral accounts:

1. Volume Deferral Account
2. Bad Debt Expense Deferral Account
3. Hearing Cost Reserve Account.

5.1 Volume Deferral Account

5.1.1 Views of the Applicant

EESI proposed to implement a Volume Deferral Account for non-energy revenue as a means of managing the uncertainty relating to forecast attrition rates for 2004.

EESI initially proposed to implement the Volume Deferral Account for variances in non-energy revenue caused by differences between the forecast and actual number of sites billed. EESI subsequently amended the proposed adjustment to be 70% of the total variance, since variable costs were estimated to be approximately 30% of the non-energy revenue requirement.

EESI confirmed that there is no Volume Deferral Account for non-energy revenue in either the current EESI tariff or the current EESAI tariff.

EESI proposed to true-up the non-energy charge on a quarterly basis based on the outstanding balance in the Volume Deferral Account.

EESI submitted that if the Volume Deferral Account was not approved by the Board, then an upward adjustment would be required to EESI's requested equity ratio of 42.5%.

EESI submitted that customers without interval meters were essentially one rate class, and that the Volume Deferral Account would, therefore, for all intents and purposes, be maintained on a rate class basis.

EESI also submitted that approval of the Volume Deferral Account on an interim basis would not shift any risk to customers.

5.1.2 Views of the Interveners

PICA submitted that the Volume Deferral Account should not be approved at this time, consistent with the risk assumptions implicit in the interim rates. PICA submitted that implementation of the Volume Deferral Account would shift risk to customers, and that customers did not have confidence in the underlying forecasts of the number of sites and attrition rates.

PICA noted that EESI confirmed that if the Volume Deferral Account was not approved at this time, the compensation for any risk associated with volume variance could be addressed in conjunction with the final capital structure determination.

PICA also submitted that the Volume Deferral Account, if allowed, should be maintained by rate class.

5.1.3 Views of the Board

Earlier in this Decision, the Board approved EESI's request to continue its current non-energy tariff on an interim basis. The Board notes that EESI's current non-energy tariff does not include a Volume Deferral Account.

The Board is not persuaded that it is appropriate to implement a Volume Deferral Account on an interim basis. The Board considers that it would be more appropriate to consider the merits of using a Volume Deferral Account that transfers risk to customers in the context of EESI's overall risk and capital structure determination.

Therefore, the Board denies EESI's request to implement a Volume Deferral Account on an interim basis.

5.2 Bad Debt Expense Deferral Account

5.2.1 Views of the Applicant

EESI proposed to implement a Bad Debt Expense Deferral Account due to its experiences over the past three years as an RRO/RRT provider. EESI submitted that actual bad debt expense has been very volatile since 2001, often as a result of factors that EESI submitted were beyond its control.

EESI confirmed that there is no Bad Debt Expense Deferral Account in either the current EESI tariff or the current EESAI tariff.

EESI does not currently track bad debt expense by rate class, but stated that a new procedure will be in operation by January 1, 2004 that will enable more accurate forecasting and reconciliation by rate class.

EESI proposed to reconcile the Bad Debt Expense Deferral Account quarterly by rate class commencing in Q3 of 2004.

EESI submitted that if the Bad Debt Expense Deferral Account was not approved by the Board, then an upward adjustment would be required to EESI's requested equity ratio of 42.5%. EESI further submitted that approval of the Bad Debt Expense Deferral Account on an interim basis would not shift any risk to customers.

5.2.2 Views of the Interveners

PICA submitted that the Bad Debt Expense Deferral Account should not be approved at this time, consistent with the risk assumptions implicit in the interim rates.

PICA submitted that EESI's forecast bad debt expense may reflect one-time adjustments as well as bad debts from EESAI, the regulated service provider in the Aquila service area.

PICA submitted that EESI should be directed to establish systems to track bad debts for EESI exclusively and by EESI's customer classes.

PICA noted that EESI confirmed that if the Bad Debt Expense Deferral Account was not approved at this time, the compensation for any risk associated with bad debt expense variance could be addressed in conjunction with the final capital structure determination.

5.2.3 Views of the Board

Earlier in this Decision, the Board approved EESI's request to continue its current non-energy tariff on an interim basis. The Board notes that the non-energy component of EESI's current tariff does not include a Bad Debt Expense Deferral Account.

Based on the evidence heard during the interim hearing, the Board shares the concerns expressed by PICA that EESI's bad debt expense may include one-time adjustments and may include bad debts from EESAI. The Board is particularly concerned that the evidence tendered by EESI in support of its position that the difficulty of forecasting bad debts justified a deferral account appeared to reflect a significant component of EESAI bad debts. In the Board's view, EESI must support its position with evidence clearly related to EESI's bad debt experience and forecasting ability.

The Board notes that EESI has very effective tools available to manage bad debt expense, including the right to collect deposits and the right to disconnect for non-payment. However, EESI provided no evidence demonstrating that it had used these tools to manage bad debts effectively in the past. In fact, some of the evidence during the hearing suggested that EESI may have failed to address certain debt collection issues in a reasonable manner. Therefore, the Board has concerns about EESI's track record in managing bad debt expense, even in the absence of a Bad Debt Expense Deferral Account. The Board is concerned that implementation of a Bad Debt Expense Deferral Account could further reduce EESI's incentive to manage bad debt expense appropriately.

Furthermore, the Board considers that it would be more appropriate to consider the merits of using a Bad Debt Expense Deferral Account to transfer risk to customers in the context of EESI's overall risk and capital structure determination in the final proceeding.

For all of these reasons, the Board denies EESI's request to implement a Bad Debt Deferral Account on an interim basis.

The Board notes EESI's commitment to track bad debt expense by EESI rate class effective January 1, 2004 and expects EESI to abide by this commitment.

5.3 Hearing Cost Reserve Account

5.3.1 Views of the Applicant

EESI proposed to establish a Hearing Cost Reserve Account due to the significant uncertainty as to the amount of hearing costs that will be incurred by EESI and interveners.

EESI proposed that the Hearing Cost Reserve Account be reconciled in subsequent applications.

5.3.2 Views of the Interveners

No interveners commented on the proposed Hearing Cost Reserve Account.

5.3.3 Views of the Board

The Board agrees with EESI that a Hearing Cost Reserve Account should be established effective January 1, 2004, consistent with the treatment of hearing costs for other utilities regulated by the Board. The Board considers EESI's forecast of hearing costs may be tested in the final proceeding.

6 EESI RESIDENTIAL RATE CLASSIFICATIO ISSUES

6.1 Introduction

Under the terms of the *RDS Regulation* in force at the time of the hearing, only "rate classification customers" as defined in the *Regulation* could be eligible for a hedged transition rate beyond the end of 2003. All other eligible customers ("non-rate classification customers" or NRCC) could only receive a flow-through rate as of January 1, 2004.

The CCG, with members in the City of Edmonton,[22] intervened in the proceedings respecting EESI's 2004 RRT Application to request that the member centers be defined in EESI's 2004 RRT as "residential rate classification customers". So defined, the CCG members would become eligible to receive a transition rate under EESI's 2004 RRT. In the alternative, the CCG at least hoped that its members would be eligible for a flow-through energy rate under EESI's 2004 RRT.

[22] Edmonton members consisting of the St Michael's Long Term Care Center Society, the Devonshire Care Center and the Good Samaritan.

While the Board was deliberating on EESI's 2004 RRT Application, as noted earlier, the Government of Alberta announced that it intended to extend the availability of the transition rate to ***all*** eligible customers through to June 30, 2006. On November 4, 2003, the Minister of Energy enacted the *RDS Amendment Regulation,* the effect of which is to require an RRT provider to offer ***only*** a transition rate to all eligible customers until June 30, 2006, and to offer ***only*** a flow-through rate to all eligible customers after July 1, 2006.

With the exception of the eligibility of St. Michael's Extended Care Center Society (St. Michael's), whose annual consumption is in excess of 250 MWh/year, the *RDS Amendment Regulation* has rendered moot the question of the eligibility of members of the CCG for a transition rate under EESI's 2004 RRT. Under the terms of the *RDS Amendment Regulation*, it is clear that any CCG member with forecast annual consumption of less than 250 MWh is an eligible customer entitled to a transition rate until June 30, 2006, whether that customer is a rate classification customer or a non-rate classification customer.

The only remaining question is whether St. Michael's can be eligible at all for service under EESI's 2004 RRT.

6.1.1 Views of the Applicant

EESI was not opposed to the Board directing EESI to include multi-unit residential buildings as residential rate classification customers. EESI believed that there was some merit in extending the definition in its RRT to include customers that have the characteristics of residential consumers even though they may not have individual meters.[23]

However, EESI noted some important caveats to its position, including the concern that a separate rate class would likely be required to accommodate such customers and that the EDI DT tariff not be affected in any way. EESI also cautioned the Board that any negotiated settlement of this issue with the CCG was not likely to be as straightforward as suggested by the CCG and would likely not be possible for implementation as of January 1, 2004, if possible at all.

6.1.2 Views of the Interveners

CCG

The CCG suggested that their concerns could be addressed if EESI included in its tariff the following definition:

> Residential rate classification customer, for the purposes of determining eligibility for a transition rate under the *Regulated Default Supply Regulation*, AR 168/2003, means all buildings or complexes that are primarily residential, including seniors' residences, long-term care facilities, residential condominiums and apartments.[24]

The CCG recognized that it would likely be necessary for EESI to procure additional hedged energy to supply these customers. The CCG also expressed confidence in its ability to negotiate a settlement with EESI for purposes of achieving a transition rate for 2004. In the alternative, the CCG at least hoped that it would be eligible for a flow-through energy rate under EESI's 2004 RRT. The CCG advised the Board that it does not have the resources to assess competitive retail

[23] Tr Pg 63
[24] Tr Pg 703

offerings, which had been suggested by EESI as an alternative. The CCG also considered that defaulting to EESI's default tariff, which is unregulated, would not be desirable.

CCA

The CCA expressed concern that any expansion of the definition of "residential rate classification customer" should be subject to a "no-harm" test such that customers presently included in the existing "residential rate classification" should not have to bear additional costs that may result from the expanded definition. The CCA noted the significant administrative challenge of determining what proportion of a building must be used for residential purposes before being included in the "residential rate classification" for the RRT and/or DT. However, the CCA encouraged the RRT and/or DT providers to explore the possibility of arriving at a definition that could be practically applied to those seeking it.

PICA

PICA noted that EESI appeared to support different classifications for DT and RRT purposes for multi-unit residential billings. The commercial classification would apply to the DT portion of tariffs applied to these customers, while the residential classification would apply to the RRT portion. Under the CCG proposal, these customers could avail themselves of the hedged energy rate in 2004. PICA felt that this approach would not be consistent with cost causation, although the administrative cost impacts, if any, had not been quantified. However, PICA was not opposed to approval of the CCG proposal on an interim basis.

6.1.3 Views of the Board

EESI, on behalf of EDI, is required by section 103 of the EUA to prepare a RRT "for the purpose of recovering the prudent costs of providing electricity services to eligible customers." The issue raised by the CCG arose originally from the eligibility requirements prescribed by the *RDS Regulation* as well as the respective entitlements to "transition" or "flow-through" rates for rate classification customers and "non-rate classification customers" set out in that *Regulation*. As already noted in the introduction to this section of the Decision, however, no issue remains in relation to CCG members with forecast annual consumption less than 250 MWh/year, whether they are rate classification customers or non-rate classification customers. Under the *RDS Amendment Regulation*, those customers are now entitled to a transition rate through to June 30, 2006.

Accordingly, the only issue remaining for the Board's consideration is whether any member of the CCG whose reasonably forecast consumption of electric energy in 2004 exceeds 250 MWh/year, such as St. Michael's, can be an "eligible customer" for purposes of EESI's 2004 RRT.

Setting up the distinction between "rate classification and "non-rate classification" customers, the definition of "eligible customer" is set out in section 1(1)(b) of the *RDS Regulation*:

> "eligible customer" means:
>
> (i) a rate classification customer, and
> (ii) any other customer, if the owner's reasonable forecast of the customer's annual consumption of electric energy at a site is less than 250 megawatt hours of electric energy at that site;

Only eligible customers according to this definition are entitled to receive service under EESI's RRT. A customer must, therefore, be either a "rate classification customer" referred to in section 1(1)(b)(i) or a customer falling within the residual class described in section 1(1)(b)(ii), which can conveniently be described as "non-rate classification customers". Annual consumption of less than 250 MWh per site is expressly prescribed in relation to non-rate classification customers.

"Rate classification customer" is specifically defined in section 1(1)(e) of the *RDS Regulation*:

> (e) "rate classification customer" means:
>
> (i) a residential rate classification customer,
> (ii) a farm rate classification customer, or
> (iii) an irrigation rate classification customer,
>
> as defined in a regulated rate tariff.

The Board was candidly advised by the CCG that St. Michael's consumes in excess of 250 MWh/year, while the other member consumes less than 250 MWh/year. The argument of the CCG was that both of its members could be deemed to be eligible for RRT service, regardless of their forecast annual consumption, if they were included in the definition of "residential rate classification customer" in EESI's 2004 RRT. The question to be decided by the Board, therefore, is whether St. Michael's can be considered either a rate classification customer or a non-rate classification customer so as to be RRT-eligible under the terms of the *RDS Regulation*, notwithstanding that its annual consumption is in excess of 250 MWh.

In the Board's view, the definitions of "rate classification customer" and "eligible customer", which are unaffected by the *RDS Amendment Regulation*, must be read together and in context. First, the Board considers it reasonable to assume that the drafters of the *RDS Regulation* would have been mindful of the definitions of residential, farm and irrigation customers contained in utility tariffs at the time of drafting. The Board notes that there are no farm or irrigation customers in the EDI service area, and that the average annual consumption for a residential customer in the EDI service area is in the range of 7 to 8 MWh/year, significantly below the 250 MWh/year non-rate classification limitation. Second, it appears clear to the Board that the two parts of the definition of "eligible customer" cannot be read in isolation from each other and that the 250 MWh/year limitation is implicit in the reference to "rate classification customer" in the definition of "eligible customer". To accept the argument that any customer can be made eligible for the transition or flow-through rate by simply designating that customer to be a "residential", "farm" or "irrigation" customer appears to contradict the clear intent of the *RDS Regulation*.

In light of these considerations, the Board is of the view that customers with forecast annual consumption in excess of 250 MWh were not intended to be eligible for any rate under a RRT. Accordingly, the Board considers that CCG customers consuming more than 250 MWh/year, such as St. Michael's, are required either to negotiate a contract with a retailer or to take service from a default supplier under the default rate. As noted by the Board during the hearing, although not obligated to do so, the appointed default provider (in this case EESI) may be able to conclude a satisfactory arrangement with these ineligible customers under the unregulated default supply rate.

The Board concludes that all customers with a forecast annual consumption in excess of 250 MWh/year are not eligible for any rate under a RRT.

7 OTHER RRT ISSUES

7.1 Billing of EDI DT Charges

7.1.1 Views of the Applicant

Effective July 1, 2004, EESI indicated that it intended to synchronize the billing data as required by section 9 of the *RDS Regulation,* which provides that:

> **9(1)** Effective July 1, 2004, for regulated rate customers,
>
> (a) both the electric energy charge and the delivery charge to customers in a billing period must be based on common consumption data for that billing period, and
>
> (b) at sites where electric energy consumption is metered, at least twice each calendar year the charge for electric energy for a billing period must be based on an actual meter reading.

For the first six months of 2004, EESI proposed to utilize its historical approach to billing the total delivery charges under which the System Access Service and Distribution Access Service charges are established on a forecast basis with no deferral accounts. As a result, EESI did not propose to reconcile the differences between total delivery charges collected from customers and total delivery charges paid to EDI.

7.1.2 Views of the Interveners

No intervener commented on the billing of EDI DT Charges.

7.1.3 Views of the Board

The Board notes that no party objected to EESI's approach of not reconciling the differences between total delivery charges collected from customers and total delivery charges paid to EDI. The Board considers that EESI's approach is a continuation of past practice and a practical alternative until synchronization of bills is implemented.

Accordingly the Board approves EESI's historical approach of not reconciling the differences between total delivery charges collected from customers and total delivery charges paid to EDI until July 1, 2004, the date required by the *RDS Regulation* for synchronization.

7.2 Billing Presentation

7.2.1 Views of the Applicant

The *RDS Regulation* indicates that:

> **8** The owner must show on every bill sent to a customer at least the following information, showing separately:
>
> (a) the electric energy charge;
>
> (b) the administrative charge, which may include a billing charge, as a dollar amount for each period specified in the bill;
>
> (c) the delivery charge for distribution access service and system access service separately as either;
>
> (i) a distribution charge and transmission charge, or
>
> (ii) a fixed delivery charge and variable delivery charge;
>
> (d) the customer's consumption of electric energy on which the charge referred to in clause (a) is based;
>
> (e) rate riders, if applicable; and
>
> (f) if applicable, shown under the heading "local access fee" any amount levied under section 45 of the *Municipal Government Act*, or Schedule 1, section 21 of the *Metis Settlements Act*, or by bylaw under the *Indian Act* (Canada).

As discussed in Section 2.5 of the Application, EESI submitted that its bills specify both a fixed delivery charge, referred to as the "fixed delivery charge," and a variable delivery charge, referred to as the "delivery consumption charge," consistent with the requirements of paragraph 8(c)(ii) of the *RDS Regulation*. EESI took the position that the requirement imposed by subsection 8(c) is not to show distribution access charges and system access service charges separately from each other, although that is an option pursuant to paragraph 8(c)(i). Rather, the requirement is to show delivery charges separately from the other charges on the bill, such as the electric energy charge.

7.2.2 Views of the Interveners

No intervener commented on billing presentation.

7.2.3 Views of the Board

The Board notes EESI's interpretation of the *RDS Regulation* and that EESI is in compliance. However, the Board observes that ENMAX Energy Corporation does separate the distribution charges from system access charges.

The Board considers it would be appropriate for EESI to further investigate the desires of EESI's customers on whether a separation of distribution charges from system access charges would be of benefit to EESI customers and directs EESI to report to the Board and interested parties at the time of the final proceeding.

7.3 Load Settlement Profiling Methodology

7.3.1 Views of the Applicant

In response to PICA's submission that EESI should use rate class specific profiles to determine consumption for NRCC, EESI indicated that EDI, as the Load Settlement Agent, determined the customer profiles used for determining the hourly consumption of non-interval metered customers. EESI had no control over metering or the consumption figures provided by EDI. EESI further indicated that EDI used net system load to profile consumption of all non-interval metered customers and that EDI had included no plans or funding to change that approach in its 2004 DT application.

EESI submitted that the issue of a change to rate class specific profiles would be more appropriately addressed in the final proceeding.

7.3.2 Views of the Interveners

PICA

PICA noted EESI's indications that for all non-interval metered customers it would use the net system load profile for calculation of energy billings and the energy deferral account. PICA noted the requirement of the *RDS Regulation* that the flow-through price will be the weighted average price by customer class for the customer's billing period. PICA submitted that the load profiles for a customer without interval metering should reflect that customer's class load profile rather than the net system load profile. PICA submitted that this change should be implemented as soon as possible to avoid cross-subsidization as between customers in different non-interval metered rate classes.

7.3.3 Views of the Board

In regard to PICA's submission that EESI should use rate class specific profiles to determine consumption for NRCC, the Board notes that under the Settlement System Code the net system load profile may be used to model any non-interval metered customer's hourly consumption.[25]

The Board considers that the merit and cost of the change that PICA suggests to EDI's approach to profiling for Load Settlement to determine the consumption used by EESI in determining its customer bills should be addressed in the final phase of the proceeding.

[25] The Alberta Electric System Operator has ongoing responsibility to ensure the appropriateness of the Code as it relates to Residential Load Settlement.

8 RCC AND NRCC TERMS AND CONDITIONS OF SERVICE

8.1 Views of the Applicant

In the Application, EESI indicated that it proposed to implement Terms and Conditions of Service (T&Cs) that were generally consistent with the T&Cs approved by the Board for EESAI.

EESI indicated that the differences between its proposed T&Cs and those approved by the Board for EESAI were as follows:

- Definitions have been updated to reflect the fact of Board regulation and the enactment of the *RDS Regulation*.
- A Force Majeure clause has been added.
- References to rate classifications that are not relevant in the EDI service territory have been deleted.
- Section 3.2 "Application for Service" reflects a requirement for 30 rather than 60 days' notice to obtain Regulated Rate Service.
- Section 3.3 "Credit Information" item (b) has been expanded to address instances in which credit information is not supplied as requested.
- Section 3.8 "Account Closure on Switch of Retailer" references no fee payable by exterior Lighting and Commercial for expedited account closure.
- Section 5 "Late Payment Charge" reflects the late payment fee that was previously approved for EESI in the EDI service territory.
- Section 7.4 "Distribution Tariff" has been added to clarify the customers obligation to provide a service connection in order to receive Regulated Rate Service and to comply with the provisions of the Distribution Tariff. The section also clarifies that EESI is responsible for making payment on behalf of the customer for distribution access service and that the customer is responsible for payment to EESI of the related charges. Accordingly, EESI may request de-enrollment of the service should the customer default on the obligations provided in the T&Cs.
- Article 10 "End of Service" has been deleted to reflect the removal of Supplier of Last Resort as a service option, and the RRT as a replacement for RRO residential and small commercial customers.

In the Revised Application, EESI amended section 3.8 of the Regulated Rate Tariff Terms and Conditions (Attached as Schedule B of this Decision) to include a revised notice period for account closure. EESI increased the notice period from "no less than 30 days" to "no less than 60 days" in the event of a customer switching to a new retailer.

8.2 Views of the Interveners

PICA

PICA did not object to the implementation of EESI's proposed T&Cs on an interim basis.

8.3 Views of the Board

The Board notes that no party objected to interim approval of the T&Cs proposed by EESI. The Board does not consider that the differences between the proposed EESI T&Cs and the T&Cs approved by the Board for EESAI[26] are significant.

Therefore, the Board approves the T&Cs proposed by EESI (Attached as Schedule B of this Decision) on an interim basis.

9 SUMMARY OF BOARD APPROVALS

This section is provided for the convenience of readers. In the event of any difference between the Directions in this section and those in the main body of the Decision, the wording in the main body of the Decision shall prevail.

1. The Board is satisfied that the proposed Residential Settlement will result in a fixed energy charge that is just and reasonable and in the public interest. Accordingly, the Board approves the fixed energy charge (including margin) that will result from the RCC 2004-2005 price setting plan on a final basis. 12
2. The Board is satisfied that the proposed NRCC 2004-2005 Plan will result in a fixed energy charge (before margin) that is just and reasonable and in the public interest. Accordingly, the Board approves the fixed energy charge (before margin) that will result from the NRCC 2004-2005 Plan on a final basis. The Board also agrees that the requested return margin for the EESI NRCC should be approved on an interim refundable basis. 18
3. Since EESI's proposed Credit Cost Factor is a new and untested concept, the Board considers that the Credit Cost Factor should only be approved on an interim refundable basis..... 18
4. The Board notes PICA's concerns about line losses and EESI's agreement that the proposed methodology for determining the line loss factor could be examined in the final proceeding. For this reason the Board considers it appropriate to approve the proposed EESI line loss methodology on an interim refundable basis. 19
5. The Board also notes that PICA requested that the Board approve the proposed Pool Trading Charges on an interim refundable basis, pending final review in the March 2004 proceeding. However, the Board notes that the formula for the energy charge includes a flow-through of the Pool Trading Charges. As a result, the Board considers it appropriate to approve the component of the energy charge formula, which involves a flow-through of the actual Pool Trading Charges on a final basis. 19
6. Therefore, the Board accepts EESI's proposal to continue its existing administrative non-energy charges for each rate classification on an interim refundable basis. 20
7. Therefore, the Board denies EESI's request to implement a Volume Deferral Account on an interim basis. 21
8. For all of these reasons, the Board denies EESI's request to implement a Bad Debt Deferral Account on an interim basis. 23

[26] The T&Cs for EESAI RRO service (which applied to both RCC and NRCC service) were approved in Decision 2000-91 dated December 29, 2000.

9. The Board concludes that all customers with a forecast annual consumption in excess of 250 MWh/year are not eligible for any rate under a RRT. 27

10. Accordingly the Board approves EESI's historical approach of not reconciling the differences between total delivery charges collected from customers and total delivery charges paid to EDI until July 1, 2004, the date required by the *RDS Regulation* for synchronization. 27

11. Therefore, the Board approves the T&Cs proposed by EESI (Attached as Schedule B of this Decision) on an interim basis. 31

10 SUMMARY OF BOARD DIRECTIONS

This section is provided for the convenience of readers. In the event of any difference between the Directions in this section and those in the main body of the Decision, the wording in the main body of the Decision shall prevail.

1. Accordingly, the Board directs EESI to file with the Board all quarterly RCC rate charges and the non-confidential calculations behind their determination that result from the implementation of the RCC 2004-2005 Plan, as a Filing for Acknowledgement. As a result, the Board will then have the current RCC rate charges on file to provide to any customer requesting this information. Further, to provide pricing information to customers as soon as possible, the Board considers that EESI should post each RCC rate class's quarterly energy price change to its website as soon as the new quarterly prices are available. 13

2. Accordingly, the Board directs EESI to facilitate discussions among the Consultation Parties to determine if agreement can be reached respecting the pooling of energy for RCC and NRCC. The Board further directs EESI to provide a report to the Board on or before February 13, 2004 summarizing the positions of parties respecting the above portfolio pooling issues. The Board will then deal with any remaining issues at the EESI final proceedings. 19

3. For the same reasons given above in relation to the RCC 2004-2005 Plan, the Board directs EESI to file with the Board all quarterly NRCC rate charges and the non-confidential calculations behind their determination that result from the implementation of the NRCC 2004-2005 Plan, as a Filing for Acknowledgement. As a result, the Board will then have the current NRCC rate charges on file to provide to any customer requesting this information. Further, to provide pricing information to customers as soon as possible, the Board considers that EESI should post each NRCC rate class's quarterly energy price change to its website as soon as the new quarterly prices are available. 19

4. The Board considers it would be appropriate for EESI to further investigate the desires of EESI's customers on whether a separation of distribution charges from system access charges would be of benefit to EESI customers and directs EESI to report to the Board and interested parties at the time of the final proceeding. 28

11 ORDER

For and subject to the reasons set out in this Decision, IT IS HEREBY ORDERED THAT:

(1) The RCC 2004-2005 Energy Price Setting Plan attached as Appendix 2 to this Decision is approved.

(2) The NRCC 2004-2005 Energy Price Setting Plan (with the exception of margin) attached as Appendix 4 to this Decision is approved.

(3) The rates in the Price Schedules attached as Schedule A to this Decision are approved on interim refundable basis effective January 1, 2004.

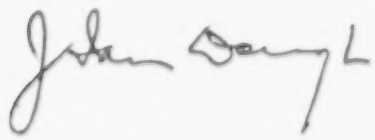
(4) The Terms and Conditions of Service attached as Schedule B to this Decision are approved on an interim refundable basis effective January 1, 2004.

Dated in Calgary, Alberta on December 5, 2003.

ALBERTA ENERGY AND UTILITIES BOARD

N. W. MacDonald, P. Eng.
Presiding Member

R. G. Lock, P. Eng.
Member



J. I. Douglas, FCA
Member

APPENDIX 1 – HEARING PARTICIPANTS

Principals and Representatives (Abbreviations Used in Report)	Witnesses
ENMAX Power Corporation (EPC) and ENMAX Energy Corporation (EEC) L. A. Cusano, Esq. D. A. Wood	EEC Dr. Ed Overcast, PhD Stuart Berry J. R. Joyce Bob Cummings Brad Thompson Allan Buchignani EPC K. Phillips Brad Thompson Allan Buchignani
EPCOR Energy Services (EESI) and EPCOR Distribution Inc. (EDI) J. M. Liteplo, Esq. D. E. Crowther, Esq.	EESI B. DeNeve Brian Gerdes EDI B. DeNeve Rick Cowburn
ATCO Electric Limited L. G. Keough, Esq. Kristen Lozynski, Esq.	
Calgary Industrial Group and Calgary Building Owners Coalition L. L. Manning, Esq	
Consumers Coalition of Alberta J. A. Wachowich	
Direct Energy Preferred P. Nigol	
Industrial Power Consumer Association M. S. Forster, Esq. Dan B. Macnamara	
Care Center Group (CCG), Edmonton Members St Michael's Long Term Care Center Society, Devonshire Care Centre and Good Samaritan Roger Bellows A. O. Ackroyd, Q. C	

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Care Center Group (CCG) Calgary Members Glamorgan Care Center, Mayfair Care Centre, Newport Harbour Care Centre Roger Bellows A. O. Ackroyd, Q. C	
Public Institutional Consumers of Alberta Nancy J. McKenzie, Esq Raj Retnanandan	
The City of Calgary D. I. Evanchuk, Esq.	
The Cities of Lethbridge, Red Deer, and University of Alberta Phyllis A. Smith, Q. C.	
Utilities Consumer Advocate C. R. McCreary Roger W. Jackson	
Board Panel N. W. MacDonald, P. Eng. R. G. Lock, P. Eng. J. I. Douglas, FCA	
Board Counsel Allan Domes, Esq.	
Board Staff Brian Ploof Kim Koshelanyk Wayne Taylor	

APPENDIX 2 – 2004 AND 2005 RRT RESIDENTIAL SETTLEMENT AGREEMENT AND ATTACHMENTS, INCLUDING THE 2004 AND 2005 PLAN

"EESI RRT
Settlement Agreemer

2004 and 2005 RRT Residential Settlement Agreement
(Consists of 5 pages)

"EESI 2004-2005
EPSP Attachment 1.c

"EESI Attachment 1
2004-05 EPSP Sched

Attachment "1" – 2004 and 2005 Residential Energy Price Setting Plan and Attached Schedules A to F
(Consists of 7 pages, and 27 pages)

"EESI Attachment 2
Energy Charge Schec

Attachment "2" – 2004 and 2005 Residential Energy Charge Schedule
(Consists of 2 pages)

"Att 3 2004 and
2005 Sett Agr.doc"

"EESI Sch A to 2004
and 2005 Code (Proc

Attachment "3" – Code of Conduct & Attached Schedule A
(Consists of 2 pages, and 2 pages)

"2004 and 2005
Consultation Agreem

Attachment "4" – Residential Consultation Agreement
(Consists of 3 pages)

Appendix "1"
to the 2004 and 2005 EESI Settlement Agreement Application
dated October 3, 2003

2004 and 2005 RRT SETTLEMENT AGREEMENT

BETWEEN:

EPCOR Energy Services Inc.
(hereinafter referred to as EESI)

- and -

Consumers Coalition of Alberta
(hereinafter referred to as CCA)

WHEREAS:

a) EPCOR Energy Services Inc. (EESI) is responsible for providing Regulated Rate Tariff (RRT) service to eligible customers in the EPCOR Distribution Inc. (EDI) service area.

b) EESI and the CCA (collectively, the Parties) have agreed upon a method for procuring energy and establishing an energy price for the 2004 and 2005 calendar years for RRT Transition Rate Customers (residential only) served under the EESI Transition Rate RRT as more particularly described in this Settlement Agreement.

IT IS HEREBY AGREED:

1.

a) Except as otherwise set out in this Settlement Agreement, for the 2004 and 2005 calendar years, the energy price applicable to EESI's RRT Transition Rate Customers served under the EESI Transition Rate RRT shall be determined in accordance with the 2004 and 2005 Energy Price Setting Plan (2004/2005 Plan), a copy of which is attached as Attachment "1" to this Settlement Agreement and the Energy Charge Schedule, a copy of which is attached at Attachment "2" to this Settlement Agreement.

b) Subject to paragraph d, EESI will include in the charges applicable to Residential Rate Classification Customers a 3.75% return margin calculated on the Energy Charge cost component of customer bills.

c) Subject to paragraph d, EESI will include in the charges applicable to RRT Transition Rate Customers a 3.25% return margin calculated on the Transmission Charge and Distribution Charge cost components of customer bills.

d) The return margins discussed in paragraphs b and c will be reduced by a percentage equal to EESI's deemed corporate tax rate in each of 2004 and 2005 unless due to a change in either provincial or federal tax legislation EESI becomes taxable. EESI's deemed corporate tax rate is expected to be 33.50% (12.50% for Alberta Provincial Tax and 21% for Federal Tax) in each of 2004 and 2005. If EESI's deemed corporate tax rate changes for any reason, EESI will notify the CCA of such change in writing and the reduction to the return margins discussed in paragraphs b and c will be calculated based on the new deemed corporate tax rate commencing beginning in the calendar quarter immediately following the effective date of the new tax rate.

e) The Energy Charge Schedule shall apply from and after January 1, 2004.

f) To the extent possible, all energy procurement under the 2004/2005 Plan will be completed concurrently and in conjunction with the procurement of electric energy to meet the obligations of EPCOR Energy Services (Alberta) Inc. to provide RRT service to eligible customers in non-EDI service areas.

g) The monthly billing (administration) charge applicable to Residential Rate Classification Customers will be dealt with as part of a separate RRT application and is expressly excluded from this Agreement.

h) The 2004/2005 Plan is to remain in effect for 2004 and 2005. Upon receiving approval from the Alberta Energy and Utilities Board (AEUB or Board) of this Settlement Agreement and the 2004/2005 Plan, EESI will schedule Product purchases of the forecast hedging requirements for 2005 for Residential Rate Classification Customers in accordance with Schedule "B" to the 2004/2005 Plan. There will be no adjustment to the price and volume of Products purchased for 2005 under any circumstances.

i) Notwithstanding anything to the contrary in the 2004/2005 Plan, the Parties may agree that all or part of the Super Peak Products for the first and fourth quarters of each of 2004 and 2005 shall be acquired through the Power Pool. To the extent that all or a portion of such Super Peak Products are acquired through the Power Pool, the return margin applied to the Energy Charge for the portion of the Super Peak Products acquired through the Power Pool shall be reduced by 75% from the level established under this Settlement Agreement.

j) The CCA agrees to support an application by EESI to the Board in the fourth quarter of 2005 for approval to recover any adjustments to the Energy Charge that may be required as a result of the 2004/2005 Plan in the first quarter of 2006.

k) The Parties agree that the Aggregate Line Loss component of the Energy Charge Schedule applicable for 2004 and 2005, for EESI RRT Transition Rate Customers, will be set equal to line losses and Unaccounted For Energy calculations approved by the AEUB for EDI based upon the most recent 12 months of final settlement results received by EESI from EDI. EESI will update the Aggregate Line Loss component on

a quarterly basis as part of the Energy Charge calculation.

l) EESI shall be required to file quarterly updates to the Energy Charges resulting from the operation of the 2004/2005 Plan with the AEUB for acknowledgement only.

2. Code of Conduct

The Parties agree that a Code of Conduct (2004/2005 Code of Conduct), that is based on the Code of Conduct developed in conjunction with the 2003 Plan approved by the Board for EESAI, and a copy of which is attached as Attachment "3" to this Settlement Agreement, will apply for the purpose of procurement under the 2004/2005 Plan. It is acknowledged and agreed that the 2004/2005 Code of Conduct is expressly for the purpose of procurement under the 2004/2005 Plan and is without prejudice to any position that the Parties may take with regard to Code of Conduct issues in any other regulatory or utility matters or proceedings.

3. Filing of Settlement Agreement with the AEUB

Following execution of this Settlement Agreement by the Parties, EESI agrees to file it with the Board for approval on an expedited basis.

4. Representations

Each of the Parties represents that it has not withheld any relevant information in the course of negotiating the Settlement Agreement.

5. Notice

EESI confirms that it has provided proper notice of the negotiation of this Settlement Agreement to all interested parties in accordance with the directions of the AEUB in that regard.

6. Support of Settlement Agreement

The CCA agrees to support an application by EESI to the AEUB for approval of this Settlement Agreement.

7. Conditions Precedent

This Settlement Agreement is contingent on the Board accepting all of the provisions of this Settlement Agreement as contemplated in Section 135 of the *Electric Utilities Act.* Unless otherwise agreed by the Parties, if the AEUB rejects this Settlement Agreement in whole or in part, this Settlement Agreement will be null and void.

8. Payment of Costs

a) EESI will pay, on an interim refundable basis, the costs incurred by the CCA in respect of the application to the AEUB for approval of this Settlement Agreement and

in respect of negotiating this Settlement Agreement on receipt of an invoice from the CCA. These costs or an estimate of these costs will be included as part of the Energy Charge in accordance with section 8 of the 2004/2005 Plan.

b) Unless otherwise agreed, the Parties agree to provide EESI applicable invoice(s) no later than thirty (30) days following issuance of an AEUB order(s) approving this Settlement Agreement (the Order(s)) and to confirm to EESI in writing that each such invoice complies with the AEUB guidelines for utility costs claims.

c) EESI will file with the AEUB a summary of costs paid by EESI to the CCA under this section within 60 days of receiving the Order(s). The summary will also include costs incurred by EESI in respect of the Application for approval of this Settlement Agreement and in respect of negotiating this Settlement Agreement, and as further described in section 8 of the 2004/2005 Plan. EESI will request that the AEUB approve the recovery of these costs as part of the RRT Energy Charge for 2004 and 2005 and the CCA will support such request The CCA will be responsible for providing any additional information the AEUB may request in respect of its cost claim(s). If the AEUB determines that all, or any portion, of the costs paid by EESI to the CCA under this Settlement Agreement may not be recovered as part of the RRT Energy Charge for 2004 and 2005, then the CCA will repay the disallowed amount to EESI within 30 days following a decision on any review or appeal made in respect of that decision or, if no review or appeal is made, within 35 days following issuance of the original cost decision.

9. General Terms and Conditions of Settlement

(a) The division of this Settlement Agreement into headings and paragraphs is for convenience and reference only and should not affect the interpretation or construction of this Settlement Agreement.

(b) This Settlement Agreement and its Attachments constitute the entire agreement between the Parties and no other agreements, expressed or implied, have been made.

(c) Any alteration or amendment of this Settlement Agreement must be in writing and signed by the Parties.

(d) This Settlement Agreement will be binding upon, and enure to the benefit of, the Parties and each of their respective trustees, administrators, successors and permitted assigns.

(e) The terms and conditions of this Settlement Agreement will be interpreted pursuant to the laws of the Province of Alberta. Further, the Courts of the Province of Alberta will have exclusive jurisdiction with respect to any and all legal proceedings which may arise in connection with this Settlement Agreement or any of its terms and conditions.

(f) If any provision of this Settlement Agreement is found to be invalid by a Court of Law, the Settlement Agreement will be read and interpreted as if the provision were omitted.

(g) The failure of any Party to exercise any right given to it under this Settlement Agreement or to insist upon the strict compliance with any of the terms or conditions in this Settlement Agreement will not constitute a waiver of any provisions with respect to any other or subsequent breach.

(h) Time will be of the essence in this Settlement Agreement and every part of this Settlement Agreement and no extension or variance of this Settlement Agreement will operate as a waiver of this provision.

(i) This Settlement Agreement may be executed in any number of counterparts with the same effect as if the Parties had signed the same copy of this Settlement Agreement. All counterparts will be construed together and constitute one and the same agreement.

(j) Unless otherwise defined in this Settlement Agreement, capitalized terms shall have the meaning ascribed to them in the 2004/2005 Plan.

DATED as of the 3rd day of October, 2003

EPCOR Energy Services Inc.

Per:_____

Consumers Coalition of Alberta

Per:_____

Attachment "1"
to the EESI 2004 and 2005 RRT Settlement Agreement
to the AEUB dated October 3, 2003

2004 AND 2005 ENERGY PRICE SETTING PLAN

1. Definitions

Capitalized terms used in this 2004 and 2005 Energy Price Setting Plan (2004/2005 Plan), that are not otherwise defined herein, have the respective meanings ascribed to those terms in Schedule "A" to this 2004/2005 Plan.

2. RRT Transition Rate Energy Cost

The energy cost component of EESI's RRT Transition Rate (applicable to Residential Classification Customers only) will be determined on the basis of the Base Energy Portfolio Price, Off-Peak Energy Portfolio Price and Peak Energy Portfolio Price in the Energy Product Portfolio established under this 2004/2005 Plan.

3. Energy Product Portfolio

(a) The Energy Product Portfolio may be made up of Monthly Products, Quarterly Products and One-Year Products.

(b) The target composition of the Energy Product Portfolio for 2004 and 2005 is set out in Schedule "B" to this 2004/2005 Plan in the case of One-Year Products and will be set out in Schedule "C" in the case of Monthly Products. Quarterly Products may be acquired as a replacement for Monthly Products as provided in the applicable Monthly Product Schedule.

(c) The target composition of the One-Year Products for 2005 will be established in accordance with the process described for Monthly Products under Section 3(d). A portion of the target composition for 2005 may be purchased in advance of 2005 in accordance with Schedule "B". The process for establishing the Monthly Product Schedules, as provided in Section 3(d), will be used for establishing the One-Year Product Portfolio for 2005.

(d) The Monthly Product Schedule for each Quarter in 2004 and 2005 will be established in the following manner:

(i) At least 7 weeks before the start of each Quarter, EESI will provide to the CCA a Monthly Product Schedule it proposes for the Quarter setting out, among other things, the EESI RRT Transition Rate Volumes of Monthly Products forecast for the Quarter comprised of Monthly Base Product, Monthly Peak Product and Monthly Super Peak Product proposed to be

acquired for each month during the Quarter for EESI RRT Transition Rate Customers, the Forecast Peak Load Portion for the Quarter, the RCFPLP for the EESI RRT Transition Rate Customers for the Quarter and the forecast energy consumption at the customer meter for EESI RRT Transition Rate Customers for the Quarter.

(ii) The CCA will have a period of 1 week to review the proposed Monthly Product Schedule and discuss the EESI RRT Transition Rate Volume forecast, the Forecast Peak Load Portion, the RCFPLP for EESI RRT Transition Rate Customers for the Quarter and the forecast energy consumption at the customer meter for each EESI RRT Transition Rate Customer for the Quarter. If the CCA agrees, the Monthly Product Schedule proposed by EESI will become the Monthly Product Schedule for the Quarter.

(iii) If the CCA does not agree with the proposed Monthly Product Schedule within the 1 week period, the matter will be immediately submitted to dispute resolution, which will be conducted as follows:

(A) A representative of EESI, the CCA and the Advisor will use their best efforts to meet to discuss the proposed Monthly Product Schedule within 2 business days after the expiration of the 1 week period. At that meeting, each party shall cooperate fully by answering any questions the other party or the Advisor may have respecting the proposed Monthly Product Schedule and the representatives of EESI and the CCA will work diligently and in good faith to reach agreement concerning the proposed Monthly Product Schedule.

(B) If no agreement is reached at the meeting provided for under section 3(c)(iii)(A), within 1 business day after the expiration of the 2 business day period, the representatives of EESI and the CCA will each submit a final proposed Monthly Product Schedule including its proposed EESI RRT Transition Rate Customer Volumes and Forecast Peak Load Portion, the RCFPLP for EESI RRT Transition Rate Customers for the Quarter and the forecast energy consumption at the customer meter for each EESI RRT Transition Rate Customer for the Quarter (**Final Proposed Monthly Product Schedule**) to each other and to the Advisor. If a party elects not to provide a Final Monthly Product Schedule within the allowed time, the Advisor will proceed to resolve the matter based on the Final Monthly Product Schedule provided by the other party.

(C) After considering the Final Proposed Monthly Product Schedule(s) submitted, the Advisor must, within 2 business days of the Final

Monthly Product Schedule(s) being submitted, select one of the following options:

(1) Decide in favour of EESI's Final Proposed Monthly Product Schedule, if submitted; or

(2) Decide in favour of the CCA's Final Proposed Monthly Product Schedule, if submitted

The Advisor will select the option that, in the opinion of the Advisor, best reflects the required EESI RRT Transition Rate Volume and Forecast Peak Load Portion, the RCFPLP for EESI RRT Transition Rate Customer for the Quarter and the forecast energy consumption at the customer meter for each EESI RRT Transition Rate Customer for the Quarter for EESI's RRT Transition Rate.

(iv) The Final Proposed Monthly Product Schedule selected by the Advisor will become the Monthly Product Schedule for the Quarter.

(v) The decision of the Advisor under Section 3(c)(iii) is final and binding on both EESI and the CCA and may not be appealed by either party to the AEUB.

(vi) All of the material provided by a party and positions taken by a party throughout the dispute resolution process are confidential and may not be disclosed by any other party without prior written consent.

4. Acquisition Process

(a) Subject to Section 4(b), EMC will conduct a series of Rounds, in accordance with the Protocol as necessary to acquire the Total RRT Transition Rate Target Volumes of each Product for the RRT Transition Rate Customers for 2004 and 2005.

(b) In the case of One-Year Products, the EESI RRT Transition Rate Volume Percentage share, as set out in Schedule "B" to this 2004 and 2005 Plan, of the total volume of each One-Year Product acquired under this 2004 and 2005 Plan, will be attributed to EESI's Energy Product Portfolio for the purpose of establishing the energy cost component of EESI's RRT Transition Rate.

(c) In the case of Monthly Products, the EESI RRT Transition Rate Volume Percentage share of the Total RRT Transition Rate Target Volume of each Monthly Product, in each case as set out in the applicable Monthly Product Schedule established in accordance with Section 3(c) above without regard for any changes to the Total RRT Transition Rate Target Volume that may subsequently made by EESI in accordance with the Monthly Product Schedule,

will be attributed to EESI's Energy Product Portfolio for the purpose of establishing the energy cost component of EESI's RRT Transition Rate.

(d) Power Pool Target Volumes will be established for scheduled Products if the acquisition process, in accordance with the Protocol, produces prices which exceed the Threshold Prices. Threshold Prices are included in Schedule "B" for One-Year Products and Schedule "C" for Monthly Products. The Power Pool Target Volumes will remain in place unless the CCA agrees to either purchase the scheduled Target Volumes at prices greater than the Threshold Prices or reschedule the acquisition of the Products.

5. Determination of Energy Portfolio Prices

(a) Following completion of Product acquisition for any specified period, the Base Energy Portfolio Price, the Off-Peak Energy Portfolio Price and Peak Energy Portfolio Price will be determined for that period.

(b) As soon as practicable prior to the start of each Quarter of 2004 and 2005, EESI will provide to the CCA, the energy price for the Quarter determined in accordance with the formulas set out in the Energy Charge Schedule approved by the AEUB for 2004 and 2005. The CCA will have a 1 week period to review the energy price after which it will be filed with the AEUB for acknowledgement and will be implemented at the start of the Quarter.

(c) EESI will file the resulting energy price with the Board for acknowledgment before the start of each Quarter in 2004 and 2005.

6. Timelines

(a) The first series of Rounds to acquire Products for the EESI RRT Transition Rate Customers and attribute Products to EESI's Energy Product Portfolio for 2004 and 2005 will commence immediately upon Board approval and will continue in accordance with the timelines set out in Schedule "B" to this Plan as required to acquire the Total RRT Transition Rate Target Volumes for One-Year Products for 2004 and 2005.

(b) Subject to Section 4 above, subsequent series of Rounds will be conducted to acquire Monthly Products for the RRT Transition Rate Customers and to attribute Monthly Products to the Energy Product Portfolio in accordance with the timelines set out in the applicable Monthly Product Schedules.

7. Consultation and Dispute Resolution Process

7.1 Designation of Representatives and Board Observer

Prior to first series of Rounds for each of 2004 and 2005, EESI will designate an individual and an alternate to represent it, and the CCA will designate an individual and an alternate to represent them during the Rounds (**Representative**). The designated Representative will work in good faith to facilitate the carrying out of the Rounds as contemplated by this 2004/2005 Plan.

7.2 Representation during Rounds

Rounds are dynamic processes where it is essential to be able to make decisions in a timely and efficient manner to respond to changing circumstances. The Representatives of EESI and the CCA will be available during each Round and, working with the Advisor, will have authority to agree to modifications to the Protocol as necessary to respond to particular circumstances that may arise during the Round with the objective of reducing Energy Portfolio Prices. If, during a Round, the Representatives of EESI and the CCA do not agree on a particular modification, the Round will continue without the modification.

7.3 Certification following Round

Within 2 business days following the completion of each Round, EESI will prepare and circulate to the Representative of the CCA and the Advisor, a Certification of Compliance for that Round certifying that EESI has carried out that Round in compliance with the requirements of this 2004/2005 Plan. Unless the Representatives of EESI and the CCA agree to proceed, a subsequent Round will not be initiated until the respective Representatives of EESI, the CCA and the Advisor, who were present at the Round, have signed the Certification of Compliance for the Round.

7.4 Consultation Process between Rounds

Representatives of EESI and the CCA will meet with the Advisor within 2 business days or such other time as they may agree following the end of each Round. The Representatives and the Advisor will review the results of the Round and any market developments or trends that any party may reasonably believe will have a material impact on the continued implementation of the 2004/2005 Plan. This could include, but is not limited, to significant changes in market prices or EESI RRT Transition Rate load requirement. At the request of either party, EESI and the CCA will work in good faith to identify any improvements that can be made to the Protocol taking into account the matters discussed above. EESI and the CCA will work diligently to agree on any amendments to the Protocol that may be necessary to implement the identified improvements.

7.5 Dispute Resolution

(a) If the Representatives of EESI and the CCA are unable to agree pursuant to Section 7.4 as to whether any improvements need to be made to the Protocol or on any amendments necessary to implement any identified improvement, subject to

Section 7.5(k), either EESI or the CCA (**Disputing Party**) may at any time invoke the dispute resolution process (**Dispute Resolution Process**) under this Section 7.5 by providing a written notice (**Dispute Notice**) to the other party, the Advisor and the Board Observer. The Dispute Notice must:

(i) identify the specific change that is proposed (**Proposed Change**) and the impact the Proposed Change would reasonably be expected to have on RRT rates, if any; and

(ii) identify the reason for the Proposed Change and the harm that would reasonably be expected to occur if the Proposed Change is not made.

(b) The Representatives of EESI and the CCA, the Advisor and the Board Observer will use their best efforts to meet to discuss the Proposed Change within 2 business days of the Dispute Notice being provided. At that meeting, the Disputing Party invoking the Dispute Resolution Process shall cooperate fully by answering any questions the other party (**Other Party**), the Advisor or the Board Observer may have respecting the Proposed Change and the Representatives of EESI and the CCA will work diligently and in good faith to reach agreement concerning the Proposed Change.

(c) If no agreement is reached at the meeting provided for under section 7.5(b), the Disputing Party must provide written notice (**Election Notice**) to the Other Party, the Advisor and the Board Observer within 1 business day of the conclusion of the meeting if it wishes to continue the Dispute Resolution Process.

(d) If the Disputing Party elects to continue the Dispute Resolution Process pursuant to Section 7.5(c), the Other Party may provide written notice (**Continuation Notice**) to the Disputing Party within 1 business day of receiving the Election Notice advising the Disputing Party whether it agrees to continue the Dispute Resolution Process.

(e) If the Disputing Party does not provide the Election Notice as provided under section 7.5(c), or if the Other Party provides a Continuation Notice advising that it does not agree to continue the Dispute Resolution Process or does not provide the Continuation Notice as provided under section 7.5(d), the Disputing Party will be free to pursue the Proposed Change with the AEUB provided that the Disputing Party must ask the AEUB to decide the matter on an expedited basis and respect the confidential nature of the matters to be addressed to the extent permitted under the AEUB's rules of practice.

(f) If the Other Party agrees to continue the Dispute Resolution Process under Section 7.5(d), then both the Disputing Party and the Other Party will submit a "Final Proposal" (**Final Proposal**) in respect of the matters addressed in the Dispute Notice, to each other, the Advisor and the Board Observer within 1 business day of the Continuation Notice being provided. Any Final Proposal submitted must include the information required to be included in the Dispute

Notice. If a party elects not to provide a Final Proposal within the allowed time, the Advisor and the Board Observer will proceed to resolve the matter based on the Final Proposal provided by the other party.

(g) After considering the Final Proposal(s) submitted, the Advisor and the Board Observer must, within 2 business days of the Final Proposal(s) being submitted, select one of the following options:

(i) Decide that no change should be made to the 2004/2005 Plan;

(ii) Decide in favour of EESI's Final Proposal, if submitted; or

(iii) Decide in favour of the CCA's Final Proposal, if submitted

The Advisor and Board Observer will select the option that is most consistent with the intent of the parties as reflected in the 2004/2005 Plan.

(h) If the Advisor and Board Observer both select either EESI's or the CCA's Final Proposal, then the 2004/2005 Plan will be amended in accordance with that Final Proposal. If both the Advisor and the Board Observer both decide that no change should be made to the 2004/2005 Plan, then no changes will be made to the 2004/2005 Plan. If the Advisor and the Board Observer select different Final Proposals, then no change will be made to the 2004/2005 Plan.

(i) The decision of the Advisor and the Board Observer under Section 7.5(h) concerning the Proposed Changes to the 2004/2005 Plan is final and binding on both EESI and the CCA and may not be appealed by either party to the AEUB.

(j) All of the material provided by a party and positions taken by a party throughout the Dispute Resolution Process are confidential and may not be disclosed by any other party without the written consent of that party.

(k) The Dispute Resolution Process may not be initiated once a Round has commenced. Unless the Representatives of EESI and the CCA agree to proceed, no Rounds will be initiated while a Dispute Resolution Process is underway.

8. Costs

Costs incurred by EESI and the CCA in relation to the 2004/2005 Plan including, costs related to any dispute resolution matter, whether before the AEUB or Board Observer and Advisor, and the costs of the Advisor and AEUB administration costs will be included in the energy costs for EESI's RRT Transition Rate Customers.

Schedule A
to the 2004 and 2005 Energy Price Setting Plan
dated October 3, 2003

DEFINITIONS

1. General Definitions

In the 2004 and 2005 Energy Price Setting Plan (**2004/2005 Plan**),

Advisor means an independent expert retained by EESI and the CCA to provide advice and assistance as provided in the 2004/2005 Plan;

AEUB means the Alberta Energy and Utilities Board;

Board Observer means the individual designated by the AEUB to observe and assist as provided in the 2004/2005 Plan;

CCA means the Consumers Coalition of Alberta;

Certification of Compliance means, (i) in relation to a RFO Round, a certification that EESI has carried out that RFO Round in compliance with the requirements of the 2004/2005 Plan, in the form of the Certification of Compliance attached as Schedule "E" to the 2004/2005 Plan, with such modifications as may be necessary to reflect the particular details of that RFO Round, and (ii) in relation to Inter-Round Procurement, a certification that EESI has carried out the Inter-Round Procurement in compliance with the 2004/2005 Plan, in the form of the Certification of Compliance attached as Schedule "F" to the 2004/2005 Plan.

EDI Service Area means the service area of EPCOR Distribution Inc. in Alberta;

EMC means EPCOR Merchant & Capital L.P.;

EUI means EPCOR Utilities Inc.;

Exchanges means (i) the online internet trading systems for electrical energy in Alberta operated by Alberta Watt Exchange Ltd., and (ii) NGX Canada Inc.;

Inter-Round Procurement means an Inter-Round process, administered by the Advisor, conducted in accordance with the Inter-Round Protocol;

Method means, the energy price setting method set out in the 2004/2005 Plan;

Monthly Product Schedule means, in relation to a Quarter, a schedule for the Quarter in the applicable form attached as Schedule "C" to the 2004/2005 Plan setting out, among other things, the Total RRT Transition Rate Volumes, Total RRT Transition Rate Target Volume, EESI RRT Transition Rate Volumes and EESI RRT Transition Rate Volume

Percentage, the Forecast Peak Load Portion for EESI's RRT Transition Rate Customer for that Quarter, the RCFPLP for each EESI RRT Transition Rate Customer for the Quarter and the forecast energy consumption at the customer meter for each EESI RRT Transition Rate Customer for the Quarter;

Protocol means the RFO Protocol;

Q1 means January, February and March of 2004 or 2005;

Q2 means April, May and June of 2004 or 2005;

Q3 means July, August and September of 2004 or 2005;

Q4 means October, November and December of 2004 or 2005;

Quarters means Q1, Q2, Q3 and Q4 and **Quarter** means any of Q1, Q2, Q3 or Q4;

RFO means, in relation to a Product, a request for an offer made by EESI to a Qualified Supplier for supplies of that Product;

RFO Protocol means the Protocol for RFO Round attached as Schedule "D" to the 2004/ 2005 Plan;

RFO Round means a RFO process, administered by the Advisor, conducted in accordance with the RFO Protocol;

Round means a RFO Round;

RRT means a regulated rate tariff as contemplated under section 103 of the Electric Utilities Act S.A. 2003, c. E-5.1;

RRT Transition Rate means a regulated rate tariff for eligible customers approved by the AEUB under the section 103 of the Electric Utilities Act S.A. 2003, c. E-5.1;

RRT Transition Rate Customers means the customers of EESI receiving RRT Transition Rate service,

Target Volume means, in relation to a Round, the amount of Product targeted to be acquired in that Round.

2. **Product Definitions**

In the 2004/ 2005 Plan,

Base Period means the period from 00:00 hours to 24:00 hours, Monday through Sunday inclusive;

Base Product means an agreement to supply power twenty-four hours a day, seven days a week and may include a Monthly Base Product and a One-Year Base Product;

Monthly Product means a Monthly Base Product, a Monthly Peak Product or a Monthly Off-Peak Product;

Monthly Base Product means a Base Product having a one-month term;

Monthly Off-Peak Product means a Monthly Off-Peak (7x8) Product, or a Monthly Super Off-Peak (7x18) Product having a one-month term

Monthly Off-Peak (7x8) Product means an Off-Peak (7x8) Product having a one-month term;

Monthly Super Off-Peak (7x18) Product means a Super Off-Peak (7x18) Product having a one-month term;

Monthly Peak Product means a Monthly Peak (7x16) Product, or a Monthly Super Peak (7x6) Product;

Monthly Peak (7x16) Product means a Peak (7x16) Product having a one-month term;

Monthly Super Peak (7x6) Product means a Super Peak (7x6) Product having a one-month term;

Off-Peak (7x8) Period means the period from 0:00 hours to 7:00 hours and from 23:00 hours to 0:00 hours, Monday through Sunday inclusive;

Off-Peak Periods means Off-Peak (7x8) Periods, Super Off-Peak (7x18) Periods and

Off-Peak Period means any of Off-Peak (7x8) Period, or Super Off-Peak (7x18) Period as the context may require.

Off-Peak Product means an agreement to supply power during an Off-Peak Period and may include a Monthly Off-Peak Product and/or a One-Year Off-Peak Product;

Off-Peak (7x8) Product means an agreement to supply power during a Peak (7x8) Period;

One-Year Product means a One-Year Base Product, a One-Year Peak Product or a One-Year Off-Peak Product;

One-Year Base Product means a Base Product having a one-year term;

One-Year Off-Peak Product means a One-Year Off-Peak (7x8) Product;

One-Year Off-Peak (7x8) Product means an Off-Peak (7x8) Product having a one-year term;

One-Year Peak Product means a One-Year Peak (7x16) Product;

One-Year Peak (7x16) Product means a Peak (7x16) Product having a one-year term;

Peak (7x16) Period means the period from 7:00 hours to 23:00 hours, Monday through Sunday inclusive;

Peak Periods means Peak (7x16) Periods, Super Peak (7x6) Periods and **Peak Period** means either of a Peak (7x16) Period, or Super Peak (7x6) Period as the context may require;

Peak Product means an agreement to supply power during a Peak Period and may include a Monthly Peak Product and/or a One-Year Peak Product;

Peak (7x16) Product means an agreement to supply power during a Peak (7x16) Period;

Product means a Base Product, a Peak Product or an Off-Peak Product;

Quarterly Base Product means a Base Product having a one Quarter term;

Quarterly Off-Peak Product means a Quarterly Off-Peak (7x8) Product;

Quarterly Off-Peak (7x8) Product means an Off-Peak (7x8) Product having a one-Quarter term;

Quarterly Product means a Quarterly Base Product, a Quarterly Peak Product, or a Quarterly Off-Peak Product;

Quarterly Peak Product means a Quarterly Peak (7x16) Product;

Quarterly Peak (7x16) Product means a Peak (7x16) Product having a one-Quarter term;

Quarterly Product means a Quarterly Base Product or a Quarterly Peak Product;

Shoulder Peak Period means a Peak Period excluding the Super Peak Period portion of the Peak Period;

Super Off-Peak (7x18) Period means the period from 0:00 hours to 16:00 hours and 22:00 hours to 0:00 hours, Monday through Sunday inclusive;

Super Off-Peak (7x18) Product means an agreement to supply power during a Super Off-Peak (7x18) Period;

Super Peak (7x6) Period means the period from 16:00 hours to 22:00 hours, Monday through Sunday inclusive, including holidays.

Super Peak (7x6) Product means an agreement to supply power during a Super Peak (7x6) Period;

3. Price, Volume and Portfolio Definitions

In the 2004/2005 Plan,

Base Energy Portfolio Price means, for a Quarter, the average price (weighted by volume) of the Base Products in the Energy Product Portfolio for that period, expressed in $/MWh;

EESI RRT Transition Rate Classification has the meaning given to that term in the EESI RRT Transition Rate Price Schedule.

EESI RRT Transition Rate Volumes means (i) in relation to One-Year Products for a year, EESI's reasonable forecast of the total volume of One-Year Base Products and One-Year Peak Products required (with separate procurement) for its RRT Transition Rate Customers in the EDI Service Area as set out in Table 1 of Schedule "B" to the 2004/2005 Plan and (ii) in relation to Monthly Products, EESI's reasonable forecast of the volume of Monthly Base Products and Monthly Peak Products required (with separate procurement) for its RRT Transition Rate Customers in the ANCA Service Area for a month, as set out in the Monthly Product Schedule for the Quarter in which that month occurs.

EESI RRT Transition Rate Volume Percentage means (i) in relation to One-Year Products for a year, EESI's reasonable forecast of the total volume of One-Year Base Products and One-Year Peak Products required (with separate procurement) for its RRT Transition Rate Customers in the EDI Service Area relative to the total volume of One-Year Base Products and One-Year Peak Products required (with separate procurement) for RRT Transition Rate Customers as set out in Table 1 of Schedule "B" to the 2004/2005 Plan and (ii) in relation to Monthly Products, EESI's reasonable forecast of the volume of Monthly Base Products and Monthly Peak Products required (with separate procurement) for its RRT Transition Rate Customers in the EDI Service Area for a month relative to the total volume of Monthly Base Products and Monthly Peak Products required (with separate procurement) for RRT Transition Rate Customers as set out in the Monthly Product Schedule for the Quarter in which that month occurs.

Energy Portfolio Prices means, for a Quarter, the Base Energy Portfolio Price, the Off Peak Energy Portfolio Price and the Peak Energy Portfolio Price for that period;

Energy Product Portfolio means, at a point in time, the portfolio of Base Products and Peak Products that have then been acquired or deemed to have been acquired for the Energy Product Portfolio pursuant to the 2001 Plan, and the 2004/2005 Plan and the terms of which have not expired at that time;

Forecast Price means, in relation to a Monthly Product for the second or third month of a Quarter:

(i) the price of an offer (if any) or, if there are more than one, the simple average of the prices of offers for volumes of at least 5MW of the energy product corresponding to the Monthly Product recorded, during the last Round conducted to acquire the Monthly Product for the first month of the Quarter, from the Exchange Screens (as defined in the applicable Protocol) at the time the indicative Heat Rate is being determined under Step 2 of the RFO Round Protocol; or

(ii) if the price referred to in (i) of this definition is not available, the last transacted price (if any) or, it there is more than one, the simple average of the last transacted prices for volumes of at least 5MW of the energy product corresponding to the Monthly Product obtained from the Exchanges (as defined in the applicable Protocol) at the time referred to in (i) of this definition; or

(iii) if prices referred to in (i) and (ii) of this definition are not available and the Quarter is:

(A) the first, second or third Quarter, EESI will propose a price for the Monthly Product to the representative of the CCA and they will work diligently and in good faith to agree on the price and the Forecast Price for the Monthly Product will be the agreed price or, failing agreement within two business days, the actual price for the Monthly Product acquired for the first month of the Quarter; or

(B) the fourth Quarter, the Forecast Price for the Monthly Product will be the Proposed Monthly Product Price or, when available, the Monthly Product Price established as provided below in this definition.

If (iii)(B) of this definition applies, EESI will propose a price for the Monthly Product (**Proposed Monthly Product Price**) to the representative of the CCA. If the representative of the CCA does not agree with the Proposed Monthly Product Price, the parties will work diligently and in good faith with each other and the Advisor to reach agreement. Either EESI or the representative of the CCA may at any time invoke the Dispute Resolution Process under Section 7.5 of the 2004/ 2005 Plan by providing a Dispute Notice to the other party. The price agreed on by EESI and the CCA or determined pursuant to the Dispute Resolution Process (**Monthly Product Price**) will be the Forecast Price for the Monthly Product. Pending agreement or determination of the Monthly Product Price, the Proposed Monthly Product Price will be used for the purposes of the Section 5 of the Energy Price Setting Plan.

Forecast Peak Load Portion (FPLP) means, in relation to a Quarter, the value set out in Table 1d of the Monthly Product Schedule for that Quarter.

Off-Peak Energy Portfolio Cost means, for a period, the amount determined by subtracting the Peak Energy Portfolio Cost from the Total Energy Portfolio Cost for that period.

Off-Peak Energy Portfolio Price means, for a Quarter, the amount determined as follows:

OPEPP = OPEPC/[TEPV x (1 – FPLP)]

where:

OPEPP is the Off-Peak Energy Portfolio Price for that Quarter, expressed in $/MWh;

OPEPC is the Off-Peak Energy Portfolio Cost for that Quarter;

TEPV is the Total Energy Portfolio Volume for that Quarter;

FPLP is the Forecast Peak Load Portion for that Quarter;

Peak Energy Portfolio Cost means, for a Quarter, the amount determined as follows:

PEPC = TEPV x FPLP x PEPP

where:

PEPC is the Peak Energy Portfolio Cost for that Quarter, expressed in $/MWh;

TEPV is the Total Energy Portfolio Volume for that Quarter;

FPLP is the Forecast Peak Load Portion for that Quarter;

PEPP is the Peak Energy Portfolio Price for that Quarter;

Peak Energy Portfolio Price means, in the case of Q1, the Peak Energy Portfolio Price (Unadjusted) for that Quarter and in the case of each of the other Quarters, the Peak Energy Portfolio Price (Unadjusted) plus the Peak Energy Portfolio Price Adjustment for that Quarter if it is a positive amount or minus the Peak Energy Portfolio Price Adjustment for that Quarter if it is a negative amount;

Peak Energy Portfolio Price (Unadjusted) means, for a Quarter, the price for Peak Products included in the Energy Product for that Quarter which will be equal to the quotient of:

(a) the sum of:

(i) $YP(7x16)PMW_y$ x $QP(7x16)PH_Q$ x $YP(7x16)PP_y$;

(ii) $MP(7x16)PMW_{m1\text{-}for}$ x $MP(7x16)PH_{m1}$ x $MP(7x16)PP_{m1\text{-}act}$;

(iii) $MP(7x16)PMW_{m2\text{-}for}$ x $MP(7x16)PH_{m2}$ x $MP(7x16)PP_{m2\text{-}for}$;

(iv) $MP(7x16)PMW_{m3\text{-}for}$ x $MP(7x16)PH_{m3}$ x $MP(7x16)PP_{m3\text{-}for}$;

(v) $MSP(7x6)PMW_{m1\text{-}for} \times MSP(7x6)PH_{m1} \times MSP(7x6)PP_{m1\text{-}act}$;

(vi) $MSP(7x6)PMW_{m2\text{-}for} \times MSP(7x6)PH_{m2} \times MSP(7x6)PP_{m2\text{-}for}$;

(vii) $MSP(7x6)PMW_{m3\text{-}for} \times MSP(7x6)PH_{m3} \times MSP(7x6)PP_{m3\text{-}for}$; and

(viii) $QP(7x16)PMWq \times QP(7x16)PH_Q \times QP(7x16)PP_Q$;

divided by;

(b) the sum of:

(i) $YP(7x16)PMW_y \times QP(7x16)PH_Q$;

(ii) $MP(7x16)PMW_{m1\text{-}for} \times MP(7x16)PH_{m1}$;

(iii) $MP(7x16)PMW_{m2\text{-}for} \times MP(7x16)PH_{m2}$;

(iv) $MP(7x16)PMW_{m3\text{-}for} \times MP(7x16)PH_{m3}$;

(v) $MSP(7x6)PMW_{m1\text{-}for} \times MSP(7x6)PH_{m1}$;

(vi) $MSP(7x6)PMW_{m2\text{-}for} \times MSP(7x6)PH_{m2}$;

(vii) $MSP(7x6)PMW_{m3\text{-}for} \times MSP(7x6)PH_{m3}$; and,

(viii) $QP(7x16)PMW_Q \times QP(7x16)PH_Q$;

where:

$YP(7x16)PMW_y$ is the total capacity of One-Year Peak (7x16) Products, expressed in MWs, acquired for the Energy Product Portfolio for 2004or 2005

$QP(7x16)PH_Q$ is the total number of hours in Peak (7x16) Periods that occur in that Quarter;

$YP(7x16)PP_y$ is the average (weighted by capacity acquired) of the prices of the One Year Peak (7x16) Products acquired for the Energy Product Portfolio for 2004 or 2005;

$MP(7x16)PMW_{m1\text{-}for}$ is the total capacity of Monthly Peak (7x16) Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the first month of that Quarter;

$MP(7x16)PH_{m1}$ is the total number of hours in Peak (7x16) Periods that occur in the first month of that Quarter;

MP(7x16)PP$_{m1\text{-}act}$ is the average (weighted by capacity acquired) of the prices of the Monthly Peak (7x16) Products acquired for the Energy Product Portfolio for the first month of that Quarter;

MP(7x16)PMW$_{m2\text{-}for}$ is the total capacity of Monthly Peak (7x16) Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the second month of that Quarter;

MP(7x16)PH$_{m2}$ is the total number of hours in Peak (7x16) Periods that occur in the second month of that Quarter;

MP(7x16)PP$_{m2\text{-}for}$ is the Forecast Price of the Monthly Peak (7x16) Products to be acquired for the Energy Product Portfolio for the second month of that Quarter;

MP(7x16)PMW$_{m3\text{-}for}$ is the total capacity of Monthly Peak (7x16) Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the third month of that Quarter;

MP(7x16)PH$_{m3}$ is the total number of hours in Peak (7x16) Periods that occur in the third month of that Quarter;

MP(7x16)PP$_{m3\text{-}for}$ is the Forecast Price of the Monthly Peak (7x16) Products to be acquired for the Energy Product Portfolio for the third month of that Quarter;

MSP(7x6)PMW$_{m1\text{-}for}$ is the total capacity of Monthly Super Peak (7x6) Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the first month of that Quarter;

MSP(7x6)PH$_{m1}$ is the total number of hours in Super Peak (7x6) Periods that occur in the first month of that Quarter;

MSP(7x6)PP$_{m1\text{-}act}$ is the average price (weighted by capacity purchased) of the Monthly Super Peak (7x6) Products acquired for the Energy Product Portfolio for the first month of that Quarter;

MSP(7x6)PMW$_{m2\text{-}for}$ is the total capacity of Monthly Super Peak (7x6) Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the second month of that Quarter;

MSP(7x6)PH$_{m2}$ is the total number of hours in Super Peak (7x6) Periods that occur in the second month of that Quarter;

MSP(7x6)PP$_{m2\text{-}for}$ is the Forecast Price of the Monthly Super Peak (7x6) Products to be acquired for the Energy Product Portfolio for the second month of that Quarter;

MSP(7x6)PMW$_{m3\text{-}for}$ is the total capacity of Monthly Super Peak (7x6) Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the third month of that Quarter;

MSP(7x6)PH$_{m3}$ is the total number of hours in Super Peak (7x6) Periods that occur in the third month of that Quarter;

MSP(7x6)PP$_{m3\text{-}for}$ is the Forecast Price of the Monthly Super Peak (7x6) Products to be acquired for the Energy Product Portfolio for the third month of that Quarter;

QP(7x16)PMW$_{Q}$ is the total capacity of Quarterly Peak (7x16) Products, expressed in MWs, acquired for the Energy Product Portfolio for that Quarter;

QP(7x16)PP$_{Q}$ is the average (weighted by capacity acquired) of the prices of the Quarterly Peak (7x16) Products acquired for the Energy Product Portfolio for that Quarter;

Peak Energy Portfolio Price Adjustment means, for a Quarter, the positive or negative adjustment to the Peak Energy Portfolio Price (Unadjusted) for that Quarter for the actual prices of Monthly Peak Products acquired for the Energy Product Portfolio for the second and third months of the immediately preceding Quarter which will be a positive or negative amount equal to the quotient of:

(a) the sum of:

(i) $MP(7x16)PMW_{m2(Q-1)\text{-}for} \times MP(7x16)PH_{m2(Q-1)} \times (MP(7x16)PP_{m2(Q-1)\text{-}act} - MP(7x16)PP_{m2(Q-1)\text{-}for})$;

(ii) $MP(7x16)PMW_{m3(Q-1)\text{-}for} \times MP(7x16)PH_{m3(Q-1)} \times (MP(7x16)PP_{m3(Q-1)\text{-}act} - MP(7x16)PP_{m3(Q-1)\text{-}for})$;

(iii) $MSP(7x6)PMW_{m2(Q-1)\text{-}for} \times MSP(7x6)PH_{m2(Q-1)} \times (MSP(7x6)PP_{m2(Q-1)\text{-}act} - MSP(7x6)PP_{m2(Q-1)\text{-}for})$

(iv) $MSP(7x6)PMW_{m3(Q-1)\text{-}for} \times MSP(7x6)PH_{m3(Q-1)} \times (MSP(7x6)PP_{m3(Q-1)\text{-}act} - MSP(7x6)PP_{m3(Q-1)\text{-}for})$;

divided by;

(b) the sum of:

(i) $YP(7x16)PMW_{y} \times QP(7x16)PH_{Q}$;

(ii) $MP(7x16)PMW_{m1\text{-}for} \times MP(7x16)PH_{m1}$;

(iii) $MP(7x16)PMW_{m2\text{-}for} \times MP(7x16)PH_{m2}$;

(iv) $MP(7x16)PMW_{m3\text{-}for} \times MP(7x16)PH_{m3}$;

(v) $MSP(7x6)PMW_{m1\text{-}for} \times MSP(7x6)PH_{m1}$;

(vi) $MSP(7x6)PMW_{m2\text{-}for} \times MSP(7x6)PH_{m2}$;

(vii) $MSP(7x6)PMW_{m3\text{-}for} \times MSP(7x6)PH_{m3}$;

(viii) $QP(7x16)PMW_{Q} \times QP(7x16)PH_{Q}$;

where:

$YP(7x16)PMW_{y}$ is the total capacity of One-Year Peak (7x16) Products, expressed in MWs, acquired for the Energy Product Portfolio for 2004 and 2005;

$QP(7x16)PH_{Q}$ is the total number of hours in Peak (7x16) Periods that occur in the Quarter for which the Peak Energy Portfolio Price Adjustment is being determined;

$MP(7x16)PMW_{m2(Q-1)\text{-}for}$ is the total capacity of Monthly Peak (7x16) Products, expressed in MWs, forecast in the Monthly Product Schedule for the immediately preceding Quarter to be acquired for the Energy Product Portfolio for the second month of that Quarter;

$MP(7x16)PH_{m2(Q-1)}$ is the total number of hours in Peak (7x16) Periods that occur in the second month of the immediately preceding Quarter;

$MP(7x16)PP_{m2(Q-1)\text{-}act}$ is the average (weighted by capacity acquired) of the prices of the Monthly Peak (7x16) Products to be acquired for the Energy Product Portfolio for the second month of the immediately preceding Quarter;

$MP(7x16)PP_{m2(Q-1)\text{-}for}$ is the Forecast Price of the Monthly Peak (7x16) Products to be acquired for the Energy Product Portfolio for the second month of the immediately preceding Quarter;

$MP(7x16)PMW_{m3(Q-1)\text{-}for}$ is the total capacity of Monthly Peak (7x16) Products, expressed in MWs, forecast in the Monthly Product Schedule for the immediately preceding Quarter to be acquired for the Energy Product Portfolio for the third month of that Quarter;

$MP(7x16)PH_{m3(Q-1)}$ is the total number of hours in Peak (7x16) Periods that occur in the third month of the immediately preceding Quarter;

$MP(7x16)PP_{m3(Q-1)\text{-}act}$ is the average (weighted by capacity acquired) of the prices of the Monthly Peak (7x16) Products acquired for the Energy Product Portfolio for the third month of the immediately preceding Quarter;

MP(7x16)PP$_{m3(Q-1)\text{-}for}$ is the Forecast Price of the Monthly Peak (6x16) Products to be acquired for the Energy Product Portfolio for the third month of the immediately preceding Quarter;

MSP(7x6)PH$_Q$ is the total number of hours in Super Peak (7x6) Periods that occur in the Quarter for which the Peak Energy Portfolio Price Adjustment is being determined;

MSP(7x6)PMW$_{m2(Q-1)\text{-}for}$ is the total capacity of Monthly Super Peak (7x6) Products, expressed in MWs, forecast in the Monthly Product Schedule for the immediately preceding Quarter to be acquired for the Energy Product Portfolio for the second month of that Quarter;

MSP(7x6)PH $_{m2(Q-1)}$ is the total number of hours in Super Peak (7x6) Periods that occur in the second month of the immediately preceding Quarter;

MSP(7x6)PP$_{m2(Q-1)\text{-}act}$ is the average (weighted by capacity acquired) of the prices of the Monthly Super Peak (7x6) Products acquired for the Energy Product Portfolio for the second month of the immediately preceding Quarter;

MSP(7x6)PP$_{m2(Q-1)\text{-}for}$ is the Forecast Price of the Monthly Super Peak (7x6) Products to be acquired for the Energy Product Portfolio for the second month of the immediately preceding Quarter;

MSP(7x6)PMW$_{m3(Q-1)\text{-}for}$ is the total capacity of Monthly Super Peak (7x6) Products, expressed in MWs, forecast in the Monthly Product Schedule for the immediately preceding month to be acquired for the Energy Product Portfolio for the third month of that Quarter;

MSP(7x6)PH $_{m3(Q-1)}$ is the total number of hours in Super Peak (7x6) Periods that occur in the third month of the immediately preceding Quarter;

MSP(7x6)PP$_{m3(Q-1)\text{-}act}$ is the average (weighted by capacity acquired) of the prices of the Monthly Super Peak (7x6) Products acquired for the Energy Product Portfolio for the third month of the immediately preceding Quarter;

MSP(7x6)PP$_{m3(Q-1)\text{-}for}$ is the Forecast Price of the Monthly Super Peak (7x6) Products to be acquired for the Energy Product Portfolio for the third month of the immediately preceding Quarter;

MP(7x16)PMW$_{m1\text{-}for}$ is the total capacity of Monthly Peak (7x16) Products, expressed in MWs, forecast in the Monthly Product Schedule for the Quarter for which the Peak Energy Portfolio Price Adjustment is being determined to be acquired for the Energy Product Portfolio for the first month of that Quarter;

MP(7x16)PH$_{m1}$ is the total number of hours in Peak (7x16) Periods that occur in the first month of the Quarter for which the Peak Energy Portfolio Price Adjustment is being determined;

MP(7x16)PMW$_{m2\text{-}for}$ is the total capacity of Monthly Peak (7x16) Products, expressed in MWs, forecast in the Monthly Product Schedule for the Quarter for which the Peak Energy Portfolio Price Adjustment is being determined to be acquired for the Energy Product Portfolio for the second month of that Quarter;

MP(7x16)PH$_{m2}$ is the total number of hours in Peak (7x16) Periods that occur in the second month of the Quarter for which the Peak Energy Portfolio Price Adjustment is being determined;

MP(7x16)PMW$_{m3\text{-}for}$ is the total capacity of Monthly Peak (7x16) Products, expressed in MWs, forecast in the Forecast for the Quarter for which the Peak Energy Portfolio Price Adjustment is being determined to be acquired for the Energy Product Portfolio for the third month of that Quarter;

MP(7x16)PH$_{m3}$ is the total number of hours in Peak (7x16) Periods that occur in the third month of the Quarter for which the Peak Energy Portfolio Price Adjustment is being determined;

QP(7x16)PMW$_{y}$ is the total capacity of Quarterly Peak (7x16) Products, expressed in MWs, acquired for the Energy Product Portfolio for the Quarter for which the Peak Energy Portfolio Price Adjustment is being determined;

Product Ratio means an agreed upon ratio of Peak Product or Super Peak Product to Base Product as determined in accordance with Schedule B or C for an RFO Round, that if exceeded, the representative of the CCA will have an option to purchase the next Product closest to (or including) Base Product (i.e. Peak Product as a replacement for Super Peak Product or Base Product as a replacement for Peak Product).

Rate Classification Forecast Peak Load Portion (RCFPLP) means, in relation to an EESI RRT Transition Rate Customer for a Quarter, the value for that EESI RRT Transition Rate Customer set out in Table 1e of the Monthly Product Schedule for that Quarter.

Threshold Price means an agreed upon price, as determined in either Schedule B or C (as applicable), that if exceeded, the representative of the CCA will have an option of requesting that EESI not purchase the required Product volumes in an RFO Round.

Total Energy Portfolio Cost (Unadjusted) means, for a Quarter, the amount equal to the sum of:

(i) $YBPMW_y \times QBPH_Q \times YBPP_y$;

(ii) $MBPMW_{m1\text{-}for} \times MBPH_{m1} \times MBPP_{m1\text{-}act}$;

(iii) $MBPMW_{m2\text{-}for} \times MBPH_{m2} \times MBPP_{m2\text{-}for}$;

(iv) $MBPMW_{m3\text{-}for} \times MBPH_{m3} \times MBPP_{m3\text{-}for}$;

(v) $YP(7x16)PMW_y \times QP(7x16)PH_Q \times YP(7x16)PP_y$;

(vi) $MP(7x16)PMW_{m1\text{-}for} \times MP(7x16)PH_{m1} \times MP(7x16)PP_{m1\text{-}act}$;

(vii) $MP(7x16)PMW_{m2\text{-}for} \times MP(7x16)PH_{m2} \times MP(7x16)PP_{m2\text{-}for}$;

(viii) $MP(7x16)PMW_{m3\text{-}for} \times MP(7x16)PH_{m3} \times MP(7x16)PP_{m3\text{-}for}$;

(ix) $MSP(7x6)PMW_{m1\text{-}for} \times MSP(7x6)PH_{m1} \times MSP(7x6)PP_{m1\text{-}act}$;

(x) $MSP(7x6)PMW_{m2\text{-}for} \times MSP(7x6)PH_{m2} \times MSP(7x6)PP_{m2\text{-}for}$;

(xi) $MSP(7x6)PMW_{m3\text{-}for} \times MSP(7x6)PH_{m3} \times MSP(7x6)PP_{m3\text{-}for}$;

(xii) $QBPMW_Q \times QBPH_Q \times QBPP_Q$; and

(xiii) $QP(7x16)PMW_Q \times QP(7x16)PH_Q \times QP(7x16)PP_Q$;

where:

$YBPMW_y$ is the total capacity of One-Year Base Products, expressed in MWs, acquired for the Energy Product Portfolio for 2004 or 2005;

$QBPH_Q$ is the total number of hours in Base Periods that occur in that Quarter;

$YBPP_y$ is the average (weighted by capacity acquired) of the prices of the One Year Base Products acquired for the Energy Product Portfolio for 2004 or 2005;

$MBPMW_{m1\text{-}for}$ is the total capacity of Monthly Base Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the first month of that Quarter;

$MBPH_{m1}$ is the total number of hours in Base Periods that occur in the first month of that Quarter;

$MBPP_{m1\text{-}act}$ is the average (weighted by capacity acquired) of the prices of the Monthly Base Products acquired for the Energy Product Portfolio for the first month of that Quarter;

$MBPMW_{m2\text{-}for}$ is the total capacity of Monthly Base Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the second month of that Quarter;

$MBPH_{m2}$ is the total number of hours in Base Periods that occur in the second month of that Quarter;

MBPP$_{m2\text{-}for}$ is the Forecast Price of the Monthly Base Products to be acquired for the Energy Product Portfolio for the second month of that Quarter;

MBPMW$_{m3\text{-}for}$ is the total capacity of Monthly Base Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the third month of that Quarter;

MBPH $_{m3}$ is the total number of hours in Base Periods that occur in the third month of that Quarter;

MBPP$_{m3\text{-}for}$ is the Forecast Price of the Monthly Base Products to be acquired for the Energy Product Portfolio for the third month of that Quarter;

YP(7x16)PMW$_y$ is the total capacity of One-Year Peak (7x16) Products, expressed in MWs, acquired for the Energy Product Portfolio for 2004or 2005;

QP(7x16)PH$_Q$ is the total number of hours in Peak (7x16) Periods that occur in that Quarter;

YP(7x16)PP$_y$ is the average (weighted by capacity acquired) of the prices of the One Year Peak (7x16) Products acquired for the Energy Product Portfolio for 2004 or 2005;

MP(7x16)PMW$_{m1\text{-}for}$ is the total capacity of Monthly Peak (7x16) Products, expressed in MWs, forecast in the Monthly Product Schedule to that Quarter to be acquired for the Energy Product Portfolio for the first month of that Quarter;

MP(7x16)PH$_{m1}$ is the total number of hours in Peak (7x16) Periods that occur in the first month of that Quarter;

MP(7x16)PP$_{m1\text{-}act}$ is the average (weighted by capacity acquired) of the prices of the Monthly Peak (7x16) Products acquired for the Energy Product Portfolio for the first month of that Quarter;

MP(7x16)PMW$_{m2\text{-}for}$ is the total capacity of Monthly Peak (7x16) Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the second month of that Quarter;

MP(7x16)PH$_{m2}$ is the total number of hours in Peak (7x16) Periods that occur in the second month of that Quarter;

MP(7x16)PP$_{m2\text{-}for}$ is the Forecast Price of the Monthly Peak (7x16) Products to be acquired for the Energy Product Portfolio for the second month of that Quarter;

MP(7x16)PMW$_{m3\text{-}for}$ is the total capacity of Monthly Peak (7x16) Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the third month of that Quarter;

MP(7x16)PH$_{m3}$ is the total number of hours in Peak (7x16) Periods that occur in the third month of that Quarter;

MP(7x16)PP$_{m3\text{-}for}$ is the Forecast Price of the Monthly Peak (6x16) Products to be acquired for the Energy Product Portfolio for the third month of that Quarter;

MSP(7x6)PMW$_{m1\text{-}for}$ is the total capacity of Monthly Super Peak (7x6) Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the first month of that Quarter;

MSP(7x6)PH$_{m1}$ is the total number of hours in Super Peak (7x6) Periods that occur in the first month of that Quarter;

MSP(7x6)PP$_{m1\text{-}act}$ is the average price (weighted by capacity purchased) of the Monthly Super Peak (7x6) Products acquired for the Energy Product Portfolio for the first month of that Quarter;

MSP(7x6)PMW$_{m2\text{-}for}$ is the total capacity of Monthly Super Peak (7x6) Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio I for the second month of that Quarter;

MSP(7x6)PH$_{m2}$ is the total number of hours in Super Peak (7x6) Periods that occur in the second month of that Quarter;

MSP(7x6)PP$_{m2\text{-}for}$ is the Forecast Price of the Monthly Super Peak (7x6) Products to be acquired for the Energy Product Portfolio for the second month of that Quarter;

MSP(7x6)PMW$_{m3\text{-}for}$ is the total capacity of Monthly Super Peak (7x6) Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the third month of that Quarter;

MSP(7x6)PH$_{m3}$ is the total number of hours in Super Peak (7x6) Periods that occur in the third month of that Quarter;

MSP(7x6)PP$_{m3\text{-}for}$ is the Forecast Price of the Monthly Super Peak (7x6) Products to be acquired for the Energy Product Portfolio for the third month of that Quarter;

QBPMW$_{Q}$ is the total capacity of Quarterly Base Products, expressed in MWs, acquired for the Energy Product Portfolio for that Quarter;

QP(7x16)PMW$_{Q}$ is the total capacity of Quarterly Peak (7x16) Products, expressed in MWs, acquired for the Energy Product Portfolio for that Quarter;

$QP(7x16)PP_Q$ is the average (weighted by capacity acquired) of the prices of the Quarterly Peak (7x16) Products acquired for the Energy Product Portfolio for that Quarter;

Total Energy Portfolio Cost Adjustment means, for a Quarter, the positive or negative adjustment to the Total Energy Portfolio Cost (Unadjusted) for that Quarter for the actual prices of Monthly Products acquired for the Energy Product Portfolio for the second and third months of the immediately preceding Quarter which will be a positive or negative amount equal to the sum of:

(i) $MBPMW_{m2(Q-1)\text{-}for} \times MBPH_{m2(Q-1)} \times (MBPP_{m2(Q-1)\text{-}act} - MBPP_{m2(Q-1)\text{-}for})$;

(ii) $MBPMW_{m3(Q-1)\text{-}for} \times MBPH_{m3(Q-1)} \times (MBPP_{m3(Q-1)\text{-}act} - MBPP_{m3(Q-1)\text{-}for})$;

(iii) $MP(7x16)PMW_{m2(Q-1)\text{-}for} \times MP(7x16)PH_{m2(Q-1)} \times (MP(7x16)PP_{m2(Q-1)\text{-}act} - MP(7x16)PP_{m2(Q-1)\text{-}for})$;

(iv) $MP(7x16)PMW_{m3(Q-1)\text{-}for} \times MP(7x16)PH_{m3(Q-1)} \times (MP(7x16)PP_{m3(Q-1)\text{-}act} - MP(7x16)PP_{m3(Q-1)\text{-}for})$;

(v) $MSP(7x6)PMW_{m2(Q-1)\text{-}for} \times MSP(7x6)PH_{m2(Q-1)} \times (MSP(7x6)PP_{m2(Q-1)\text{-}act} - MSP(7x6)PP_{m2(Q-1)\text{-}for})$

(vi) $MSP(7x6)PMW_{m3(Q-1)\text{-}for} \times MSP(7x6)PH_{m3(Q-1)} \times (MSP(7x6)PP_{m3(Q-1)\text{-}act} - MSP(7x6)PP_{m3(Q-1)\text{-}for})$;

where:

$MBPMW_{m2(Q-1)\text{-}for}$ is the total capacity of Monthly Base Products, expressed in MWs, forecast in the Monthly Product Forecast for the immediately preceding Quarter to be acquired for the Energy Product Portfolio for the second month in that Quarter;

$MBPH_{m2(Q-1)}$ is the total number of hours in Base Periods that occur in the second month of the immediately preceding Quarter;

$MBPP_{m2(Q-1)\text{-}act}$ is the average (weighted by capacity acquired) of the prices of the Monthly Base Products acquired for the Energy Product Portfolio for the second month of the immediately preceding Quarter;

$MBPP_{m2(Q-1)\text{-}for}$ is the Forecast Price of the Monthly Base Products to be acquired for the Energy Product Portfolio for the second month of the immediately preceding Quarter;

$MBPMW_{m3(Q-1)\text{-}for}$ is the total capacity of Monthly Base Products, expressed in MWs, forecast in the Monthly Product Schedule for the immediately preceding Quarter to be acquired for the Energy Product Portfolio for the third month of that Quarter;

MBPH $_{m3(Q-1)}$ is the total number of hours in Base Periods that occur in the third month of the immediately preceding Quarter;

MBPP $_{m3(Q-1)\text{-}act}$ is the average (weighted by capacity acquired) of the prices of the Monthly Base Products acquired for the Energy Product Portfolio for the third month of the immediately preceding Quarter;

MBPP $_{m3(Q-1)\text{-}for}$ is the Forecast Price of the Monthly Base Products to be acquired for the Energy Product Portfolio for the third month of the immediately preceding Quarter;

MP(7x16)PMW$_{m2(Q-1)\text{-}for}$ is the total capacity of Monthly Peak (7x16) Products, expressed in MWs, forecast in the Monthly Product Schedule for the immediately preceding Quarter to be acquired for the Energy Product Portfolio for the second month of that Quarter;

MP(7x16)PH $_{m2(Q-1)}$ is the total number of hours in Peak (7x16) Periods that occur in the second month of the immediately preceding Quarter;

MP(7x16)PP$_{m2(Q-1)\text{-}act}$ is the average (weighted by capacity acquired) of the prices of the Monthly Peak (7x16) Products to be acquired for the Energy Product Portfolio for the second month of the immediately preceding Quarter;

MP(7x16)PP$_{m2(Q-1)\text{-}for}$ is the Forecast Price of the Monthly Peak (7x16) Products to be acquired for the Energy Product Portfolio for the second month of the immediately preceding Quarter;

MP(7x16)PMW$_{m3(Q-1)\text{-}for}$ is the total capacity of Monthly Peak (7x16) Products, expressed in MWs, forecast in the Monthly Product Schedule for the immediately preceding Quarter to be acquired for the Energy Product Portfolio for the third month of that Quarter;

MP(7x16)PH$_{m3(Q-1)}$ is the total number of hours in Peak (7x16) Periods that occur in the third month of the immediately preceding Quarter;

MP(7x16)PP$_{m3(Q-1)\text{-}act}$ is the average (weighted by capacity acquired) of the prices of the Monthly Peak (6x16) Products acquired for the Energy Product Portfolio for the third month of the immediately preceding Quarter;

MP(7x16)PP$_{m3(Q-1)\text{-}for}$ is the Forecast Price of the Monthly Peak (6x16) Products to be acquired for the Energy Product Portfolio for the third month of the immediately preceding Quarter;

MSP(7x6)PMW$_y$ is the total capacity of One-Year Super Peak (7x6) Products, expressed in MWs, acquired for the Energy Product Portfolio for 2004/ 2005

MSP(7x6)PH$_Q$ is the total number of hours in Super Peak (7x6) Periods that occur in the Quarter for which the Peak Energy Portfolio Price Adjustment is being determined;

MSP(7x6)PMW$_{m2(Q-1)-for}$ is the total capacity of Monthly Super Peak (7x6) Products, expressed in MWs, forecast in the Monthly Product Schedule for the immediately preceding Quarter to be acquired for the Energy Product Portfolio for the second month of that Quarter;

MSP(7x6)PH $_{m2(Q-1)}$ is the total number of hours in Super Peak (7x6) Periods that occur in the second month of the immediately preceding Quarter;

MSP(7x6)PP$_{m2(Q-1)-act}$ is the average (weighted by capacity acquired) of the prices of the Monthly Super Peak (7x6) Products acquired for the Energy Product Portfolio for the second month of the immediately preceding Quarter;

MSP(7x6)PP$_{m2(Q-1)-for}$ is the Forecast Price of the Monthly Super Peak (7x6) Products to be acquired for the Energy Product Portfolio for the second month of the immediately preceding Quarter;

MSP(7x6)PMW$_{m3(Q-1)-for}$ is the total capacity of Monthly Super Peak (7x6) Products, expressed in MWs, forecast in the Monthly Product Schedule for the immediately preceding month to be acquired for the Energy Product Portfolio for the third month of that Quarter;

MSP(7x6)PH $_{m3(Q-1)}$ is the total number of hours in Super Peak (7x6) Periods that occur in the third month of the immediately preceding Quarter;

MSP(7x6)PP$_{m3(Q-1)-act}$ is the average (weighted by capacity acquired) of the prices of the Monthly Super Peak (7x6) Products acquired for the Energy Product Portfolio for the third month of the immediately preceding Quarter;

MSP(7x6)PP$_{m3(Q-1)-for}$ is the Forecast Price of the Monthly Super Peak (7x6) Products to be acquired for the Energy Product Portfolio for the third month of the immediately preceding Quarter;

Total Energy Portfolio Price means, for a Quarter, the average price (weighted by volume) of the Products in the Energy Product Portfolio for that period, expressed in $/MWh;

Total Energy Portfolio Volume means, for a Quarter, the total volume of Products in the Energy Product Portfolio for that Quarter which will be equal to the sum of:

(i) $YBPMW_y \times QBPH_Q$;

(ii) $MBPMW_{m1\text{-}for} \times MBPH_{m1}$;

(iii) $MBPMW_{m2\text{-}for} \times MBPH_{m2}$;

(iv) $MBPMW_{m3\text{-}for}$ x $MBPH_{m3}$;

(v) $YP(7x16)PMW_y$ x $QP(7x16)PH_Q$;

(vi) $MP(7x16)PMW_{m1\text{-}for}$ x $MP(7x16)PH_{m1}$;

(vii) $MP(7x16)PMW_{m2\text{-}for}$ x $MP(7x16)PH_{m2}$;

(viii) $MP(7x16)PMW_{m3\text{-}for}$ x $MP(7x16)PH_{m3}$;

(ix) $MSP(7x6)PMW_{m1\text{-}for}$ x $MSP(7x6)PH_{m1}$;

(x) $MSP(7x6)PMW_{m2\text{-}for}$ x $MSP(7x6)PH_{m2}$;

(xi) $MSP(7x6)PMW_{m3\text{-}for}$ x $MSP(7x6)PH_{m3}$;

(xii) $QBPMW_Q$ x $QBPH_Q$; and

(xiii) $QP(7x16)PMW_Q$ x $QP(7x16)PH_Q$;

where:

$YBPMW_y$ is the total capacity of One-Year Base Products, expressed in MWs, acquired for the Energy Product Portfolio for 2004 or 2005;

$QBPH_Q$ is the total number of hours in Base Periods that occur in that Quarter;

$MBPMW_{m1\text{-}for}$ is the total capacity of Monthly Base Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the first month of that Quarter;

$MBPH_{m1}$ is the total number of hours in Base Periods that occur in the first month of that Quarter;

$MBPMW_{m2\text{-}for}$ is the total capacity of Monthly Base Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the second month of that Quarter;

$MBPH_{m2}$ is the total number of hours in Base Periods that occur in the second month of that Quarter;

$MBPMW_{m3\text{-}for}$ is the total capacity of Monthly Base Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the third month of that Quarter;

$MBPH_{m3}$ is the total number of hours in Base Periods that occur in the third month of that Quarter;

YP(7x16)PMW$_y$ is the total capacity of One-Year Peak (7x16) Products, expressed in MWs, acquired for the Energy Product Portfolio for 2004/ 2005;

QP(7x16)PH$_Q$ is the total number of hours in Peak (7x16) Periods that occur in that Quarter;

MP(7x16)PMW$_{m1\text{-}for}$ is the total capacity of Monthly Peak (7x16) Products, expressed in MWs, forecast in the Monthly Product Schedule to that Quarter to be acquired for the Energy Product Portfolio for the first month of that Quarter;

MP(7x16)PH$_{m1}$ is the total number of hours in Peak (7x16) Periods that occur in the first month of that Quarter;

MP(7x16)PMW$_{m2\text{-}for}$ is the total capacity of Monthly Peak (7x16) Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the second month of that Quarter;

MP(7x16)PH$_{m2}$ is the total number of hours in Peak (7x16) Periods that occur in the second month of that Quarter;

MP(7x16)PMW$_{m3\text{-}for}$ is the total capacity of Monthly Peak (7x16) Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the third month of that Quarter;

MP(7x16)PH$_{m3}$ is the total number of hours in Peak (7x16) Periods that occur in the third month of that Quarter;

MSP(7x6)PMW$_{m1\text{-}for}$ is the total capacity of Monthly Super Peak (7x6) Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the first month of that Quarter;

MSP(7x6)PH$_{m1}$ is the total number of hours in Super Peak (7x6) Periods that occur in the first month of that Quarter;

MSP(7x6)PMW$_{m2\text{-}for}$ is the total capacity of Monthly Super Peak (7x6) Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio I for the second month of that Quarter;

MSP(7x6)PH$_{m2}$ is the total number of hours in Super Peak (7x6) Periods that occur in the second month of that Quarter;

MSP(7x6)PMW$_{m3\text{-}for}$ is the total capacity of Monthly Super Peak (7x6) Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the third month of that Quarter;

$MSP(7x6)PH_{m3}$ is the total number of hours in Super Peak (7x6) Periods that occur in the third month of that Quarter;

$QBPMW_Q$ is the total capacity of Quarterly Base Products, expressed in MWs, acquired for the Energy Product Portfolio for that Quarter;

$QP(7x16)PMW_Q$ is the total capacity of Quarterly Peak (7x16) Products, expressed in MWs, acquired for the Energy Product Portfolio for that Quarter;

Total RRT Transition Rate Target Volumes means (i) in relation to One-Year Products for a year, EESI's reasonable forecast of the total volume of One-Year Base Products and One-Year Peak Products required (with joint procurement) for the RRT Transition Rate Customers as set out in either Table 1 or Table 2 of Schedule "B" to the 2004/2005 Plan and (ii) in relation to Monthly Products, EESI's reasonable forecast of the volume of Monthly Base Products and Monthly Peak Products required (with joint procurement) for the RRT Transition Rate Customers for a month, as set out in the Monthly Product Schedule for the Quarter in which that month occurs.

Total RRT Transition Rate Volumes means (i) in relation to One-Year Products for a year, EESI's reasonable forecast of the total volume of One-Year Base Products and One-Year Peak Products required (with separate procurement) for the RRT Transition Rate Customers as set out in either Table 1 or Table 2 of Schedule "B" to the 2004/2005 Plan and (ii) in relation to Monthly Products, EESI's reasonable forecast of the volume of Monthly Base Products and Monthly Peak Products required (with separate procurement) for the RRT Transition Rate Customers for a month, as set out in the Monthly Product Schedule for the Quarter in which that month occurs.

Schedule B
to the 2004 and 2005 Energy Price Setting Plan
dated October, 3 2003

COMPOSITION OF TARGET ENERGY PORTFOLIO – ONE-YEAR PRODUCTS

The contents of this Schedule constitute Commercially Sensitive Information and therefore are excluded from any public filing with the AEUB.

Schedule C
to the 2004 and 2005 Energy Price Setting Plan
dated October 3, 2003

FORMS OF MONTHLY PRODUCT SCHEDULES

The contents of this Schedule constitute Commercially Sensitive Information and therefore are excluded from any public filing with the AEUB.

Schedule D
to the 2004 and 2005 Energy Price Setting Plan
dated October 3, 2003

PROTOCOL FOR RFO ROUND

The contents of this Schedule constitute Commercially Sensitive Information and therefore are excluded from any public filing with the AEUB.

Schedule E
to the 2004 and 2005 Energy Price Setting Plan
dated October 3, 2003

CERTIFICATION OF COMPLIANCE – RFO ROUND

The contents of this Schedule constitute Commercially Sensitive Information and therefore are excluded from any public filing with the AEUB.

Schedule F
to the 2004 and 2005 Energy Price Setting Plan
dated October 3, 2003

CERTIFICATION OF COMPLIANCE – INTER-SESSION ROUND

The contents of this Schedule constitute Commercially Sensitive Information and therefore are excluded from any public filing with the AEUB.

Attachment "2"
to the EESI 2004 and 2005 RRT Settlement Agreement
to the AEUB dated October 3, 2003

Regulated Rate Tariff (RRT) Transition Rate- Price Schedule

ENERGY CHARGE SCHEDULE APPLICABLE FOR 2004/2005

The Average Energy Charge (**AEC**) applicable to each EESI RRT Transition Rate Classification for each Quarter in 2004 and 2005 will be determined as follows:

AEC = [(Peak Energy Portfolio Price x RCFPLP + Off Peak Energy Portfolio Price x (1 - RCFPLP)) x HC x LF + PTC] x (1 + RM)

where:

"Peak Energy Portfolio Price" is the Peak Energy Portfolio Price for that Quarter, expressed in $/MWh, determined in accordance with the 2004/2005 Energy Price Setting Plan.

"RCFPLP" is the EESI RRT Transition Rate Classification Forecast Peak Load Portion, as defined in Schedule "A" to the 2004/2005 Energy Price Setting Plan, for that Rate Classification for that Quarter.

"Off Peak Energy Portfolio Price" is the Off Peak Energy Portfolio Price for that Quarter, expressed in $/MWh, determined in accordance with the 2004 and 2005 Energy Price Setting Plan.

"LF" is the current Aggregate Line Loss Factor (including Unaccounted for Energy) which is applicable to the EESI's RRT Transition Rate Customers for which the AEC is being determined for 2004 and 2005.

EESI RRT Transition Rate Classification	Line Loss Factor
Residential	1.0338

"HC" is a factor of 1.0015 on account of hedging cost.

"PTC" is a flow through of the Alberta Power Pool trading charge, currently set at $0.127/MWh.

"RM" is the Return Margin for that Quarter determined as follows:

(a) if the pre-RM Average Energy Rate is less than or equal to $75/MWh, then:

RM = .0249; or

(b) if the pre-RM Average Energy Rate is greater than $75/MWh, then:

RM = [.0249 x 75 ÷ .005 x (pre-RM Average Energy Rate - 75)] / pre-RM Average Energy Rate

where:

pre-RM Average Energy Rate equals (Peak Energy Portfolio Price x RCFPLP + Off Peak Energy Portfolio Price x (1 - RCFPLP)) x HC x LF + PTC

To the extent that all or a portion of the Super Peak (7x6) Product is acquired through the Power Pool, the return margin applied for the relevant Quarter would be adjusted in accordance with the following formula:

$ARM_q = (ARM_1 \text{ X } TEPV_1 \div TEPV_q) + (ARM_2 \text{ x } TEPV_2 \div TEPV_q) + (ARM_3 \text{ x } TEPV_3 \div TEPV_q)$

where

ARM_q is the Adjusted Return Margin for the purposes of the Energy Charge Schedule for a Quarter.

ARM_1 is the Adjusted Return Margin for the first month of the Quarter based on the following formula:

$ARM_1 = \{1 - [(PPV_1 \text{ x } PPVP_1 \text{ x } 0.75) \div (TEPP_1 \text{ x } TEPV_1)]\} \text{ x } 2.49\%$

where

PPV_1 is the Pool Price Volume which is based on the total energy acquired from the Power Pool on a flow through basis for the first month of the Quarter.

$PPVP_1$ is the Pool Price Volume Price which is based on the weighted average price of the volume purchased from the Power Pool for the first month of a Quarter.

$TEPP_1$ is the Total Energy Portfolio Price which means, for the first month of a Quarter, the average price (weighted by volume) of the Products in the Energy Product Portfolio for that period, including the Pool Price Volume, expressed in $/MWh.

$TEPV_1$ is the Total Energy Portfolio Volume which means, for the first month of a Quarter, the total volume of Products in the Energy Product Portfolio for that month including the Pool Price Volume.

ARM_2 is the Adjusted Return Margin for the second month of the Quarter and is calculated based on the same formula as ARM_1 *mutatis mutandis*.

ARM_3 is the Adjusted Return Margin for the third month of the Quarter and is calculated based on the same formula as ARM_1 *mutatis mutandis*.

$TEPV_q$ is the Total Energy Portfolio Volume which means, for the Quarter, the total volume of Products in the Energy Product Portfolio for that Quarter.

Attachment "3"
to the 2004 and 2005 RRT Settlement Agreement
dated October 3, 2003

Code of Conduct for the EESI Energy Price Setting Plan

1. In addition to its own personnel, EESI may be relying on personnel of EPCOR Utilities Inc. (**EUI**), and EPCOR Merchant and Capital L.P. (**EMC**) to implement various aspects of the Plan.

2. All personnel of EESI, EUI and EMC who are privy to the commercially sensitive information relied on by the Plan (**Commercially Sensitive Information**), including specific pricing parameters, RFO and Exchange Offer energy procurement strategies, developed for the purposes of energy price setting for EESI's RRT that is bolded and italicized in the Plan (including any attachments) for identification have been or will be required to sign a Procurement Conduct Agreement requiring them to keep all Commercially Sensitive Information strictly confidential and to not disclose any Commercially Sensitive Information to any other person or use the Commercially Sensitive Information, except for the purposes of the Plan. A copy of the Procurement Conduct Agreement for new personnel is attached as Schedule "A" to this Code.

3. In order to implement the Protocol, EESI will need to disclose Commercially Sensitive Information to EMC trading personnel (**Traders**) to the extent the Traders need to know information to acquire energy for the purposes of implementing the Plan in accordance with the Protocol. Traders are not to disclose any non-public information they receive concerning the implementation of the Plan to any other person except as necessary to carry out their function of acquiring energy for the purposes of implementing the Plan in accordance with the Protocol. Provided that the information disclosed to the Trader only to the extent described above, the Trader will not be required to sign a Procurement Conduct Agreement notwithstanding Section 2.

4. EMC is not to use any non-public information it receives concerning the implementation of the Plan except for the purposes of the Plan.

5. The Advisor, any consultants (**Consultants**) retained by EESI and the CCA in respect of the Plan, and the Board Observer will be required to sign confidentiality agreements requiring them to keep all Commercially Sensitive Information strictly confidential and to not disclose any Commercially Sensitive Information to any other person or use the Commercially Sensitive Information, except for the purposes of the Plan.

6. EESI and the CCA are bound by the Consultation Agreement dated October 3, 2003 that requires both EESI and the CCA Parties to keep all Commercially Sensitive Information strictly confidential and to not disclose any Commercially Sensitive Information to any other person or use the Commercially Sensitive Information, except for the purposes of the Plan.

7. If EESI, the CCA, the Advisor, Consultants, or the Board Observer become aware of an unauthorized disclosure or unauthorized use, or a possible unauthorized disclosure or unauthorized use, of Commercially Sensitive Information (**Possible Unauthorized Use or Disclosure**) that party will immediately report that concern to each of the other parties.

8. In the event that a Possible Unauthorized Use or Disclosure is reported, EESI, the CCA, the Advisor, Consultants and the Board Observer will meet within 48 hours of the report being circulated to discuss the concerns contained in the report. If, after discussing the report, a concern remains, any party will be free to apply to the Board as it see fit, provided the party must ask the Board to respect the confidential nature of the Commercially Sensitive Information and other matters to be addressed to the extent permitted under the Board rules of practice.

Schedule "A"
to the Code of Conduct for the EESI Energy Price Setting Plan
dated October 3, 2003

PROCUREMENT CONDUCT AGREEMENT
(October, 2003)

TO: EPCOR Utilities Inc. (EUI)

WHEREAS:

A. EPCOR Energy Services Inc. (**EESI**) has adopted the energy price setting method set out in its Energy Price Setting Plan for 2004 and 2005, (**2004/2005 Plan**) for the purposes of acquiring an energy supply and setting the energy price for RRT Transition Rate customers who receive service under its RRT for EPCOR Distribution Inc. service area (**RRT Transition Rate Load**). Implementation of the 2004/2005 Plan will involve rounds of requests for offers (**RFO**) from third party suppliers to acquire an energy supply for the RRT Transition Rate Load including the use of alternative mechanisms such as forward contracts as may be agreed between EESI and the Consumers Coalition of Alberta (**CCA**).

B. The 2004/2005 Plan, as amended and adjusted from time to time, relies on the commercially sensitive information (**Commercially Sensitive Information**), including specific pricing parameters and RFO energy procurement strategies, developed for the purposes of energy price setting for EESI's RRT that is bolded and italicized in the Plan (including any attachments) for identification and has been excluded from the copy of the Plan attached as Schedule "1". The disclosure of the Commercially Sensitive Information could adversely affect EESI's ability to acquire energy supplies for the RRT customers and/or the costs incurred by EESI to acquire those supplies. EESI has entered into the Consultation Agreement dated October 3, 2003 (**Consultation Agreement**) with the CCA under which, among other things, EESI agreed to keep strictly confidential and to not use that Commercially Sensitive Information except for the purposes of the 2004/2005 Plan. A copy of the Consultation Agreement is attached as Schedule "2".

C. EUI has made efforts to identify, and to organize and manage the involvement of, directors, officers, employees and agents of EUI and it subsidiaries that have been involved or may become involved with the matters addressed in this Procurement Conduct Agreement.

NOW THEREFORE, in consideration of being permitted to become involved with the matters addressed in this Procurement Conduct Agreement, the undersigned agrees, acknowledges and confirms as follows:

1. The undersigned has read and understands the attached confidentiality provisions of the Consultation Agreement and agrees to abide by these provisions and their spirit and

intent. In particular, until the earlier of December 31, 2005 or the date the 2004/2005 Plan is no longer used or intended to be used for the purposes of energy price setting for EESI's RRT, subject to Section 2 below, the undersigned agrees to keep the Commercially Sensitive Information strictly confidential and to not disclose to any other person or use the Commercially Sensitive Information, except for the purposes of the 2004/2005 Plan.

2. The provisions of this Procurement Conduct Agreement relating to Commercially Sensitive Information will not apply to any part of such Commercially Sensitive Information that is now or subsequently becomes part of the public domain through no violation of the Procurement Conduct Agreement.

3. If the undersigned becomes aware of a breach, or of any information the undersigned believes may indicate a breach, by any other person who is a party to an agreement corresponding to this Procurement Conduct Agreement, the undersigned will immediately report that breach or possible breach to the General Counsel of EUI and to the Director of Internal Audit of EUI and conduct himself or herself in accordance with their direction.

4. The undersigned acknowledges that the mishandling or unauthorized use or disclosure by the undersigned of Commercially Sensitive Information could cause irreparable harm and significant injury to EUI and/or its subsidiaries.

5. The undersigned understands that a breach of this Procurement Conduct agreement could result in disciplinary action, if intentional, including possible termination of his or her employment or possible civil or criminal proceedings against the undersigned.

AGREED TO this _____ day of _____, 2003

_____

_____
Print Employee Name and Title

Attachment "4"
to the 2004 and 2005 RRT Settlement Agreement
dated October 3, 2003

CONSULTATION AGREEMENT

BETWEEN:

EPCOR Energy Services Inc.
(hereinafter referred to as EESI)

- and -

Consumers Coalition of Alberta
(hereinafter referred to as the CCA)

WHEREAS:

(a) EESI intends to file with the Alberta Energy and Utilities Board (AEUB) for approval of a 2004 and 2005 Energy Price Setting Plan (the Plan), setting forth EESI's price setting method (Method) for energy supplies for Regulated Rate Tariff (RRT) Transition Rate Residential Classification Customers. Excluded from copy of the Plan that will be filed with the AEUB will be any portions containing the Commercially Sensitive Information referred to in Section 2 of this Consultation Agreement.

(b) This Consultation Agreement sets out the agreement of the parties respecting ongoing consultations regarding possible amendments to the Plan and confidentiality of information.

IT IS HEREBY AGREED AS FOLLOWS:

1. **Consultation**

EESI and the CCA (collectively, the Parties) will consult in good faith from time to time regarding the possible need, and development of, adjustments and amendments to the Plan.

2. **Confidentiality**

(a) The Parties acknowledge and agree that the Method set forth in the Plan, as amended and adjusted from time to time, relies on commercially sensitive information, including specific pricing parameters, bidding strategies and details of the method for determining the energy supply products used for energy price setting for EESI's RRT as set out in Schedules "B" through "F" to the Plan (Commercially Sensitive Information). The Parties further acknowledge and agree that the disclosure of that commercially sensitive information could adversely affect EESI's ability to acquire energy supplies for the RRT customers and/or the costs incurred by EESI to acquire those supplies.

(b) The Parties agree to keep the Commercially Sensitive Information as well as any other similar information that they may receive in any consultations that they may have regarding possible adjustments or amendments to the Plan as contemplated in Section 1, strictly confidential and to not use that Commercially Sensitive Information except for the purposes of the Plan.

3. Filing with the AEUB

Following execution by all the Parties, EESI will file this Consultation Agreement with the AEUB for approval. The attached copy of the Plan will be excluded from the copy of the Consultation Agreement that will be filed with the AEUB.

4. Payment of Costs

(a) EPCOR will pay the costs reasonably incurred by the CCA in relation to this Consultation Agreement and in discussing any amendment or adjustment to the Plan on receipt of an invoice from the CCA.

(b) In addition to an invoice(s), the CCA will also indicate in writing that the costs included in the invoice(s) have been reasonably incurred and the cost claim has been prepared in accordance with the AEUB's guidelines for costs claims.

(c) EESI will include in the energy costs for the RRT Transition Rate for Residential Classification Customers the amounts paid by EESI to the CCA under this Consultation Agreement.

5. General Terms and Conditions

(a) The division of this Consultation Agreement into headings and paragraphs is for convenience and reference only and should not affect the interpretation or construction of this Consultation Agreement.

(b) This Consultation Agreement constitutes the entire agreement between the Parties and no other agreements, expressed or implied, have been made.

(c) This Consultation Agreement will be binding upon, and enure to the benefit of, the Parties and each of their respective heirs, executors, trustees, administrators, successors and permitted assigns.

(d) This Consultation Agreement may be executed in any number of counterparts.

DATED as of the 3rd day of October, 2003

EPCOR Energy Services Inc.

Per:_____

Consumers Coalition of Alberta

Per:_____

APPENDIX 3 – EESI RESIDENTIAL BILL COMPARISONS

"Residential Bill Comparison.xls"

(Consists of 4 pages)

EESI

Changes From Final 2002 Bills @ October 1 to Final 2003 Bills @ October 1

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
Rate Class Description	**Final 2002 @ October 1 ¢/kWh**	Energy Cost Change ¢/kWh	D&T Cost Change ¢/kWh	Franchise Fee Cost Change ¢/kWh	**Final 2003 @ January 1 ¢/kWh**	Energy Cost Change ¢/kWh	2001 RROT Shortfall Rider Cost Change ¢/kWh	**Final 2003 @ April 1 ¢/kWh**	Energy Cost Change ¢/kWh	D&T Cost Change ¢/kWh	**Final 2003 @ July 1 ¢/kWh**	Energy Cost Change ¢/kWh	D&T Cost Change ¢/kWh	Cessation of 2000 Deferral Rider ¢/kWh	**Final 2003 @ October 1 ¢/kWh**
Residential Service	**12.22**	0.33	0.11	0.00	**12.67**	0.00	0.22	**12.88**	0.10	0.21	**13.20**	0.00	(0.76)	(0.81)	**11.63**

Note: - Final 2002 Bills are for the 2002 calendar year.
- Final 2003 Bills are for the 2003 calendar year.
- Monthly consumption was assumed to be constant.

EESI

Changes From Final 2003 Bills @ October 1 to Final 2004 Bills @ January 1

	A	B	C	D	E	F	G	H	I	J
Rate Class Description	**Final 2003 @ October 1 ¢/kWh**	D&T Cost Change ¢/kWh	**Final 2003 @ December 1 ¢/kWh**	Energy Cost Change ¢/kWh	D&T Cost Change ¢/kWh	Franchise Fee Cost Change ¢/kWh	Cessation of 2001 RROT Shortfall Rider ¢/kWh	**Final 2004 @ January 1 ¢/kWh**	**Change (H - A) ¢/kWh**	**Change I / A %**
Residential Service	**11.63**	(0.02)	**11.61**	(0.50)	0.43	0.01	(2.20)	**9.34**	**(2.29)**	**(19.7%)**

Note: - Final 2003 Bills are for the 2003 calendar year.
- Final 2004 Bills are for the 2004 calendar year.
- Monthly consumption was assumed to be constant.

EESI

Changes From Final 2004 Bills @ January 1 to Final 2005 Bills @ January 1

	A	B	C	D	E
Rate Class Description	Final 2004 @ January 1 ¢/kWh	Energy Cost Change ¢/kWh	Final 2005 @ January 1 ¢/kWh	Change (C - A) ¢/kWh	Change D / A %
Residential Service	9.34	(0.44)	8.90	(0.44)	(4.7%)

Note: - Final 2004 Bills are for the 2004 calendar year.
- Final 2005 Bills are for the 2005 calendar year.
- Monthly consumption was assumed to be constant.

EPCOR Energy Services Inc. (EESI)
Effects of Rate and Rider Changes for Residential Service, 2002 - 2005

Energy Price Assumptions		Unit	Customer Usage Level		
2005 RROT Energy Price	4.99¢/kWh				
2004 RROT Energy Price	5.42¢/kWh				
2003 RROT Energy Price @ Oct 1, 2003	5.93¢/kWh		Low Usage	Typical Usage	High Usage
2003 RROT Energy Price @ Jul 1, 2003	5.93¢/kWh				
2003 RROT Energy Price @ Apr 1, 2003	5.83¢/kWh	kWh	300	600	1,200
2003 RROT Energy Price @ Jan 1, 2003	5.83¢/kWh	kits	1	1	1
2002 RROT Energy Price @ Oct 1, 2002	5.50¢/kWh				

Row No.	Rate Component	Relative to Row	Effective Date	Costs for Each Usage Level ($/month) and Percentage Change Relative to Specified Row					
1	October Base 2002 Rate (excludes Rate Riders and Franchise Fee)	-	Oct 1, 02	**33.87**	-	**$94.39**	-	**$95.72**	-
1a	2000 Deferral Rider	[1]	Jan 1, 02	$2.44	7.2%	$4.87	9.0%	$9.75	10.2%
1b	2001 RROT Shortfall Rider	[1]	Jan 1, 02	$5.95	17.7%	$11.89	21.9%	$23.78	24.8%
1c	Franchise Fee	[1]	Jan 1, 02	$1.11	3.3%	$2.23	4.1%	$4.45	4.6%
2	**Final 2002 Bills, Oct - Dec 2002**	[1]	Oct 1, 02	**$43.17**	**28.2%**	**$73.34**	**34.9%**	**$133.70**	**39.7%**
2a	Changes between Final 2002 Bills & 2003 Base Rate								
2b	Energy Cost Change	[2]	Jan 1, 03	$0.99	2.3%	$1.98	2.7%	$3.96	3.0%
3	**Base 2003 Rate**	[2]	Jan 1, 03	**$44.16**	**2.3%**	**$75.32**	**2.7%**	**$137.66**	**3.0%**
3a	Changes between 2002 DT Rates @ Oct 1 & 2003 DT Rates @ Jan 1								
3b	Distribution and Transmission Cost Change	[3]	Jan 1, 03	$0.43	1.0%	$0.67	0.9%	$1.15	0.8%
3c	Changes between 2002 Franchise Fee Rate @ Oct 1 & 2003 Franchise Fee Rate @ Jan 1								
3d	Franchise Fee Cost Change	[3]	Jan 1, 03	$0.01	0.0%	$0.01	0.0%	$0.04	0.0%
4	**Final 2003 Bills**	[3]	Jan 1, 03	**$44.60**	**1.0%**	**$76.00**	**0.9%**	**$138.85**	**0.8%**
4a	Changes between 2003 Base Rate @ Jan 1 & 2003 Base Rate @ Apr 1								
4b	Energy Cost Change	[4]	Apr 1, 03	-	-	-	-	-	-
5	**Base 2003 Rate**	[4]	Apr 1, 03	**$44.60**	-	**$76.00**	-	**$138.85**	-
5a	Changes between 2001 RROT Shortfall Rider @ Jan 1 & 2001 RROT Shortfall Rider @ Apr 1								
5b	2001 RROT Shortfall Rider Cost Change	[5]	Apr 1, 03	$0.64	1.4%	$1.29	1.7%	$2.57	1.9%
6	**Final 2003 Bills**	[5]	Apr 1, 03	**$45.24**	**1.4%**	**$77.29**	**1.7%**	**$141.42**	**1.9%**
6a	Changes between 2003 Base Rate @ Apr 1 & 2003 Base Rate @ Jul 1								
6b	Energy Cost Change	[6]	Jul 1, 03	$0.30	0.7%	$0.60	0.8%	$1.20	0.8%
7	**Base 2003 Rate**	[6]	Jul 1, 03	**$45.54**	**0.7%**	**$77.89**	**0.8%**	**$142.62**	**0.8%**
7a	Changes between 2003 DT Rates @ Apr 1 & 2003 DT Rates @ Jul 1								
7b	Distribution and Transmission Cost Change	[7]	Jul 1, 03	$0.64	1.4%	$1.28	1.6%	$2.56	1.8%
8	**Final 2003 Bills**	[7]	Jul 1, 03	**$46.18**	**1.4%**	**$79.17**	**1.6%**	**$145.18**	**1.8%**
8a	Changes between 2003 Base Rate @ Jul 1 & 2003 Predicted Base Rate @ Oct 1								
8b	Energy Cost Change	[8]	Oct 1, 03	$0.01	0.0%	$0.02	0.0%	$0.04	0.0%
9	**Predicted Base 2003 Rate**	[8]	Oct 1, 03	**$46.19**	**0.0%**	**$79.19**	**0.0%**	**$145.22**	**0.0%**
9a	Changes between 2003 DT Rates @ Jul 1 & 2003 DT Rates @ Oct 1								
9b	Distribution and Transmission Cost Change	[9]	Oct 1, 03	($2.27)	(4.9%)	($4.53)	(5.7%)	($9.07)	(6.2%)
9c	Cessation of 2000 Deferral Rider	[1]	Oct 24, 03	($2.44)	(5.3%)	($4.87)	(6.1%)	($9.75)	(6.7%)
10	**Final 2003 Bills**	[9]	Oct 1, 03	**$41.48**	**(10.2%)**	**$69.79**	**(11.9%)**	**$126.40**	**(13.0%)**
10a	Changes between 2003 DT Rates @ Oct 1 & 2003 DT Rates @ Dec 1								
10b	Distribution and Transmission Cost Change	[10]	Dec 1, 03	($0.07)	(0.2%)	($0.14)	(0.2%)	($0.28)	(0.2%)
11	**Final 2003 Bills**	[10]	Dec 1, 03	**$41.41**	**(0.2%)**	**$69.65**	**(0.2%)**	**$126.12**	**(0.2%)**
11a	Changes between 2003 Base Rate @ Oct 1 & 2004 Base Rate @ Jan 1								
11b	Energy Cost Change	[11]	Jan 1, 04	($1.51)	(3.7%)	($3.03)	(4.3%)	($6.05)	(4.8%)
12	**Predicted Base 2004 Rate**	[11]	Jan 1, 04	**$39.90**	**(3.7%)**	**$66.62**	**(4.3%)**	**$120.07**	**(4.8%)**
12a	Changes between 2003 DT Rates @ Dec 1 & 2004 DT Rates @ Jan 1								
12b	Distribution and Transmission Cost Change	[12]	Jan 1, 04	$1.23	3.1%	$2.56	3.8%	$5.22	4.2%
12c	Changes between 2003 Franchise Fee Rate @ Dec 1 & 2004 Franchise Fee Rate @ Jan 1								
12d	Franchise Fee Cost Change	[12]	Jan 1, 04	$0.02	0.1%	$0.04	0.1%	$0.07	0.1%
12e	Cessation of 2001 RROT Shortfall Rider	[1]	Jan 1, 04	($5.95)	(14.9%)	($11.89)	(17.8%)	($23.78)	(19.8%)
12f	Cessation of Change in 2001 RROT Shortfall Rider (to 2003 Base Rate @ Apr 1)	[5]	Jan 1, 04	($0.64)	(1.6%)	($1.29)	(1.9%)	($2.57)	(2.1%)
13	**Predicted 2004 Bills**	[12]	Jan 1, 04	**$34.56**	**(13.4%)**	**$56.03**	**(15.9%)**	**$99.01**	**(17.5%)**
13a	Changes between 2004 Base Rate @ Jan 1 & 2005 Base Rate @ Jan 1								
13b	Energy Cost Change	[13]	Jan 1, 05	($1.31)	(3.8%)	($2.62)	(4.7%)	($5.24)	(5.3%)
14	**Predicted Base 2005 Rate**	[13]	Jan 1, 05	**$33.25**	**(3.8%)**	**$53.41**	**(4.7%)**	**$93.76**	**(5.3%)**

Note: Monthly consumption was assumed to be constant.

APPENDIX 4 – EESI AMENDED APPLICATION LETTER AND ATTACHMENTS, INCLUDING THE 2004 AND 2005 NON-RATE CLASSIFICATION CUSTOMERS ENERGY PROCUREMENT PLAN

"EESI Amended
Application Letter.do

EESI Amended Application Letter
(Consists of 5 pages)

"EESI Attachment 2
NRCC Energy Price S

" EESI Schedules to
NRCC EPSP.doc"

Attachment "2"– 2004 and 2005 Non-Rate Classification Customers Energy Price Setting Plan & Attached Schedules A to F
(Consists of 8 pages and 27 pages)

"NRCC Energy
Charge Schedule.doc

Attachment "3"– 2004 and 2005 Non-Rate Classification Customers Energy Charge Schedule
(Consists of 2 pages)

"Consultation
Agreement.doc"

Attachment "4"– Non-Rate Classification Customers Consultation Agreement
(Consists of 3 pages)

EPCOR

November 18, 2003

Alberta Energy and Utilities Board
11th Floor, 10055 - 106 Street
Edmonton, Alberta
T5J 2Y2

Attention: Mr. Brian Ploof
Application Officer

Dear Sir:

Re: EPCOR Energy Services Inc.
2004 Regulated Rate Tariff Application
Board Application No. 1306820

Introduction and Approvals Requested

On November 4, 2003 (by Ministerial Order 73/2003) the Minister of Energy made the *Regulated Default Supply Amendment Regulation* (RDS Amending Regulation) and thereby amended the *Regulated Default Supply Regulation*, A.R. 168/2003 (RDS Regulation). Among other things, the amendments to the RDS Regulation stipulate that only a transition rate be provided for all eligible customers up to and including June 30, 2006.

As a consequence of the enactment of the RDS Amending Regulation, it is necessary for EESI to amend its 2004 RRT Application (Application). Specifically, the Application is hereby amended by deleting Section 5.2 and as otherwise required such that the Application no longer requests approval of either flow-through energy charges or the energy charge deferral account for non-rate classification customers (Non-RC Customers). Also, section 3.8 of the Regulated Rate Tariff Terms and Conditions (Schedule B to the Application) is amended to include a revised notice period for account closure. A copy of the revised Terms and Conditions is included as Attachment "1" to this letter.

The Application, as amended, continues to seek approval, on or before November 30, 2003, of:

a) the energy charge applicable under the regulated rate service provided to residential rate class customers that is established for 2004 by the 2004/2005 Energy Price Setting Plan;

b) the Regulated Rate Tariff Terms and Conditions (amended as discussed above); and,

c) the interim non-energy charges as discussed in section 2.1 of the Application.

EESI also continues to seek final approval, on or before November 30, 2003, of the Settlement Agreement and Energy Price Setting Plan that were filed with the Board on October 9, 2003.

As mentioned above, the amendments to the RDS Regulation that were enacted by the RDS Amending Regulation stipulate that an owner (or a party, such as EESI, that is providing regulated default supply service on behalf of an owner) provide only a transition rate for all eligible customers up to and including June 30, 2006. The principal immediate impact of this requirement is that EESI must now continue to offer after December 31, 2003 a hedged rate – rather than a flow-through rate – to what it refers to as small commercial and lighting customers.

Subparagraph 4(1)(c)(i) of the RDS Regulation, as amended, states that an owner (and thus EESI) must make arrangements to manage financial risk associated with the electric energy supply required to provide a hedged rate to its regulated default supply customers. The Energy Price Setting Plan (RCC Plan) that is the subject of the Settlement Agreement made between EESI and the Consumers Coalition of Alberta (CCA) and currently before the Board for approval, satisfies that requirement as it relates to rate classification customers. In order to satisfy the same requirement as it relates to other eligible customers (i.e., small commercial and lighting customers), EESI proposes to implement further 2004/2005 Energy Price Setting Plan (Non-RCC 2004/2005 Plan). A copy of the Non-RCC 2004/2005 Plan (excluding the confidential portions thereof[1]) is attached as Attachment "2" to this letter. EESI requests that the Board approve, on or before November 30, 2003:

a) the Non-RCC 2004/2005 Plan;

b) the approach to procuring energy and establishing the energy prices for Non-RC Customers that is described below;

c) the Energy Charge Schedule for Non-RC Customers (Non-RCC Energy Charge Schedule), a copy of which is attached as Attachment "3";

d) the Credit Cost Factor that is described below, on an interim refundable basis.

Overview of Proposed Procurement and Energy Price Setting Approach

The Non-RCC 2004/2005 Plan is, in most respects, the same as the RRC Plan. The only material difference between the Plans concerns the process to approve the load forecast volumes as described below.

Under the RCC Plan, the CCA will approve the load forecast volumes required for the operation of the Plan. EESI proposes that the Public Institutional Consumers of Alberta (PICA) serve in that role for purposes of the Non-RCC 2004/2005 Plan. PICA has extensive energy procurement

[1] EESI expects to have the confidential portions of the Non-RCC 2004/2005 Plan completed by November 24, 2003.

experience through its involvement as one of the Consultation Parties in the context of the EPCOR Energy Services (Alberta) Inc. (EESAI) Energy Price Setting Plan. EESI intends to enter a Consultation Agreement with PICA similar in form to the draft agreement that is attached as Attachment "4". Further, Mr. Sheldon Fulton (of Forte Business Solutions Ltd.) will be retained to serve in the role of independent advisor to aid in the execution of the Non-RCC 2004/2005 Plan.

EESI also proposes that, for the 2004 and 2005 calendar years, the energy price applicable under the EESI Non-RCC Regulated Rate Tariff (RRT) will be determined in accordance with the Non-RCC 2004/2005 Plan and the Non-RCC Energy Charge Schedule.

The charges applicable to Non-RC Customers will include a 3.75% return margin calculated on the energy charge cost component of customer bills. EESI will also include in the charges applicable to Non-RC Customers a 3.25% return margin calculated on the Transmission Charge and Distribution Charge cost components of customer bills. These return margins will be reduced by EESI's deemed corporate tax rate in each of 2004 and 2005. If EESI's deemed corporate tax rate changes for any reason, EESI will make the necessary adjustment to the return margin.

To the extent possible, all energy procurement under the Non-RCC 2004/2005 Plan will be completed in conjunction with the procurement of electric energy to meet the obligations of EESI to provide RRT service to rate classification customers and EESAI to provide RRT service to eligible customers in non-EDI service areas.

Notwithstanding anything to the contrary in the Non-RCC 2004/2005 Plan, EESI and PICA may agree that all or part of the Super Peak Products for the first and fourth quarters of each of 2004 and 2005 be acquired through the Power Pool. To the extent that all or a portion of such Super Peak Products are acquired through the Power Pool, the return margin applied to the energy charge for the portion of the Super Peak Products acquired through the Power Pool will be reduced by 75% from the level established under the Settlement Agreement. EESI and PICA may also agree to replace certain yearly or monthly products with longer duration products (e.g., replace Peak Product with Base Product) if certain price ratios are exceeded during procurement sessions. Any differences between the acquisition price and the deemed sale price of volumes in the shoulder or off-peak hours associated with the replacement would be factored into the calculation of the energy charge. This mechanism is also included in the RCC Plan.

The Aggregate Line Loss component of the energy charges applicable to the Non-RC Customers for 2004 and 2005 will be calculated on the basis of the most recent 12 months of final settlement results received by EESI from EDI. EESI will update the Aggregate Line Loss component on a quarterly basis as part of the energy charge calculation.

EESI will file with the Board, for acknowledgement only, quarterly updates to the energy charges resulting from the operation of the Non-RCC 2004/2005 Plan as well as the Price Schedules that reflect those energy charges.

In order to provide a hedged transition rate for the Non-RC Customers, EESI will incur incremental costs associated with posting credit with counter-parties for the purpose of procuring wholesale products under the Energy Price Setting Plan. The cost of these prudential requirements is forecast to be equal to the product of 1.5% multiplied by 28% of the actual total costs of Products procured under the Non-RCC 2004/2005 Plan. Currently, prudential requirements are expected to cover a 28% fluctuation in market prices and this provides the basis for using 28% of the procurement costs in determining the cost of prudential requirements. EESI is proposing to include these costs in the energy charge through a scaling factor (Credit Cost Factor) of 1.0042.

EESI recognizes that the concept of including the credit costs associated with the procurement of wholesale products has not been tested before the Board and therefore requests that the Credit Cost Factor be approved on an interim refundable basis effective January 1, 2004.

Projected Energy Charges

The 2003, 2004 and 2005 energy charges shown in Table 1 below have been calculated on the basis of actual prices for 2003 as well as current forward prices and estimated ratios of on-peak and on-super-peak to base prices. It should be noted that the actual energy prices would be determined only if and when the Non-RCC 2004/2005 Plan is approved and implemented and would reflect the actual procurement costs prevailing at the relevant times.

Table 1: Projected Energy Charges

$/MWh	Small Commercial	Lighting
2003 Q1	58.25	38.33
2003 Q2	58.25	38.33
2003 Q3	58.49	37.04
2003 Q4	59.63	50.12
2004 Q1	55.66	47.42
2004 Q2	53.27	33.84
2004 Q3	53.63	36.41
2004 Q4	53.65	43.04
2005 Q1	49.35	41.94
2005 Q2	49.36	30.13
2005 Q3	49.86	33.97
2005 Q4	50.27	40.23

Changes to Final Non-Energy Charges

The amendments to the RDS Regulation are expected to result in adjustments to various non-energy costs including those related to hedging implementation and information technology. However, these cost changes do not affect the interim non-energy charges for which EESI has requested approval. EESI therefore intends to file appropriate amendments respecting the final non-energy charges in due course.

A copy of this letter, with attachments, will be provided to each party on the Board's circulation list for this proceeding.

I will arrange to have 12 copies of this letter, with attachments, delivered to the Board's Calgary office by courier.

Please contact me at [780] 412-3891 if you have any questions.

Sincerely,

<original signed by>

Mike MacBeath
Manager, Retail Regulatory Affairs

cc Board's List of Interested Parties

Attachment "2"
to the EESI 2004 RRT Amended Application Letter for Non-Rate Classification Customers
dated November 18, 2003

2004 AND 2005 ENERGY PRICE SETTING PLAN

1. Definitions

Capitalized terms used in this non-rate classification customer 2004 and 2005 Energy Price Setting Plan (Non-RCC 2004/2005 Plan), that are not otherwise defined herein, have the respective meanings ascribed to those terms in Schedule "A" to this Non-RCC 2004/2005 Plan.

2. RRT Transition Rate Energy Cost

The energy cost component of EESI's RRT Transition Rate for Non-RCC will be determined on the basis of the Base Energy Portfolio Price, Off-Peak Energy Portfolio Price and Peak Energy Portfolio Price in the Energy Product Portfolio established under this Non-RCC 2004/2005 Plan.

3. Energy Product Portfolio

(a) The Energy Product Portfolio may be made up of Monthly Products, Quarterly Products and One-Year Products.

(b) The target composition of the Energy Product Portfolio for 2004 and 2005 is set out in Schedule "B" to this Non-RCC 2004/2005 Plan in the case of One-Year Products and will be set out in Schedule "C" in the case of Monthly Products. Quarterly Products may be acquired as a replacement for Monthly Products as provided in the applicable Monthly Product Schedule.

(c) The target composition of the One-Year Products for 2005 will be established in accordance with the process described for Monthly Products under Section 3(d). A portion of the target composition for 2005 may be purchased in advance of 2005 in accordance with Schedule "B". The process for establishing the Monthly Product Schedules, as provided in Section 3(d), will be used for establishing the One-Year Product Portfolio for 2005.

(d) The Monthly Product Schedule for each Quarter in 2004 and 2005 will be established in the following manner:

(i) At least 7 weeks before the start of each Quarter, EESI[1] will provide to PICA a Monthly Product Schedule it proposes for the Quarter setting out, among other things, the EESI RRT Transition Rate Non-RCC Volumes of

[1] Note that for the First Quarter of 2004 only, EESI will provide the monthly schedule to PICA by November 21, 2003.

Monthly Products forecast for the Quarter comprised of Monthly Base Product, Monthly Peak Product and Monthly Super Peak Product proposed to be acquired for each month during the Quarter for EESI RRT Transition Rate Non-RCC, the Forecast Peak Load Portion for the Quarter, the NRCFPLP for the EESI RRT Transition Rate Non-RCC for the Quarter and the forecast energy consumption at the customer meter for EESI RRT Transition Rate Non-RCC for the Quarter.

(ii) PICA's representative will have a period of 1 week to review the proposed Monthly Product Schedule and discuss the EESI RRT Transition Rate Non-RCC Volume forecast, the Forecast Peak Load Portion, the NRCFPLP for EESI RRT Transition Rate Non-RCC for the Quarter and the forecast energy consumption at the customer meter for each EESI RRT Transition Rate Non-RCC for the Quarter. If the PICA representative agrees, the Monthly Product Schedule proposed by EESI will become the Monthly Product Schedule for the Quarter.

(iii) If PICA's representative does not agree with the proposed Monthly Product Schedule within the 1 week period, the matter will be immediately submitted to dispute resolution, which will be conducted as follows:

(A) A representative of both EESI and PICA, and the Advisor will use their best efforts to meet to discuss the proposed Monthly Product Schedule within 2 business days after the expiration of the 1 week period. At that meeting, each party shall cooperate fully by answering any questions the other party or the Advisor may have respecting the proposed Monthly Product Schedule and the representatives of EESI and PICA will work diligently and in good faith to reach agreement concerning the proposed Monthly Product Schedule.

(B) If no agreement is reached at the meeting provided for under section 3(c)(iii)(A), within 1 business day after the expiration of the 2 business day period, the representatives of EESI and PICA will each submit a final proposed Monthly Product Schedule including its proposed EESI RRT Transition Rate Customer Non-RCC Volumes and Forecast Peak Load Portion, the RCFPLP for EESI RRT Transition Rate NON-RCC for the Quarter and the forecast energy consumption at the customer meter for each EESI RRT Transition Rate NON-RCC for the Quarter (**Final Proposed Monthly Product Schedule**) to each other and to the Advisor. If a party elects not to provide a Final Monthly Product Schedule within the allowed time, the Advisor will proceed to resolve the matter based on the Final Monthly Product Schedule provided by the other party.

(C) After considering the Final Proposed Monthly Product Schedule(s) submitted, the Advisor must, within 2 business days of the Final

Monthly Product Schedule(s) being submitted, select one of the following options:

(1) Decide in favour of EESI's Final Proposed Monthly Product Schedule, if submitted; or

(2) Decide in favour of PICA's Final Proposed Monthly Product Schedule, if submitted

The Advisor will select the option that, in the opinion of the Advisor, best reflects the required EESI RRT Transition Rate Non-RCC Volume and Forecast Peak Load Portion, the NRCFPLP for EESI RRT Transition Rate Non-RCC for the Quarter and the forecast energy consumption at the customer meter for each EESI RRT Transition Rate Non-RCC for the Quarter for EESI's RRT Transition Rate.

(iv) The Final Proposed Monthly Product Schedule selected by the Advisor will become the Monthly Product Schedule for the Quarter.

(v) The decision of the Advisor under Section 3(c)(iii) is final and binding on both EESI and PICA and may not be appealed by either party to the AEUB.

(vi) All of the material provided by a party and positions taken by a party throughout the dispute resolution process are confidential and may not be disclosed by any other party without prior written consent.

4. Acquisition Process

(a) Subject to Section 4(b), EMC will conduct a series of Rounds, in accordance with the Protocol as necessary to acquire the Total RRT Transition Rate Target Non-RCC Volumes of each Product for the RRT Transition Rate Non-RCC for 2004 and 2005.

(b) In the case of One-Year Products, the EESI RRT Transition Rate Non-RCC Volume Percentage share, as set out in Schedule "B" to this 2004 and 2005 Plan, of the total volume of each One-Year Product acquired under this 2004 and 2005 Plan, will be attributed to EESI's Energy Product Portfolio for the purpose of establishing the energy cost component of EESI's RRT Transition Rate.

(c) In the case of Monthly Products, the EESI RRT Transition Rate Non-RCC Volume Percentage share of the Total RRT Transition Rate Target Volume of each Monthly Product, in each case as set out in the applicable Monthly Product Schedule established in accordance with Section 3(c) above without regard for any changes to the Total RRT Transition Rate Target Volume that may subsequently made by EESI in accordance with the Monthly Product Schedule, will be attributed to EESI's Energy Product Portfolio for the purpose of establishing the energy cost component of EESI's RRT Transition Rates.

(d) Power Pool Target Volumes will be established for scheduled Products if the acquisition process, in accordance with the Protocol, produces prices which exceed the Threshold Prices. Threshold Prices are included in Schedule "B" for One-Year Products and Schedule "C" for Monthly Products. The Power Pool Target Volumes will remain in place unless the PICA representative agrees to either purchase the scheduled Target Volumes at prices greater than the Threshold Prices or reschedule the acquisition of the Products.

5. Determination of Energy Portfolio Prices

(a) Following completion of Product acquisition for any specified period, the Base Energy Portfolio Price, the Off-Peak Energy Portfolio Price and Peak Energy Portfolio Price will be determined for that period.

(b) As soon as practicable prior to the start of each Quarter of 2004 and 2005, EESI will provide to the PICA representative, the energy price for the Quarter determined in accordance with the formulas set out in the Energy Charge Schedule approved by the AEUB for 2004 and 2005. The PICA representative will have a 1 week period to review the energy price after which it will be filed with the AEUB for acknowledgement and will be implemented at the start of the Quarter.

(c) EESI will file the resulting energy price with the Board for acknowledgment before the start of each Quarter in 2004 and 2005.

6. Timelines

(a) The first series of Rounds to acquire Products for the EESI RRT Transition Rate Non-RCC and attribute Products to EESI's Energy Product Portfolio for 2004 and 2005 will commence immediately upon Board approval and will continue in accordance with the timelines set out in Schedule "B" to this Plan as required to acquire the Total RRT Transition Rate Target Volumes for One-Year Products for 2004 and 2005.

(b) Subject to Section 4 above, subsequent series of Rounds will be conducted to acquire Monthly Products for the RRT Transition Rate Non-RCC and to attribute Monthly Products to the Energy Product Portfolio in accordance with the timelines set out in the applicable Monthly Product Schedules.

7. Consultation and Dispute Resolution Process

7.1 Designation of Representatives and Board Observer

Prior to first series of Rounds for each of 2004 and 2005, EESI will designate an individual and an alternate to represent it, and PICA will designate an individual and an alternate to represent them during the Rounds (**Representative**). The designated Representative will work in good faith to facilitate the carrying out of the Rounds as contemplated by this 2004/2005 Plan.

7.2 Representation during Rounds

Rounds are dynamic processes where it is essential to be able to make decisions in a timely and efficient manner to respond to changing circumstances. The Representatives of EESI and PICA will be available during each Round and, working with the Advisor, will have authority to agree to modifications to the Protocol as necessary to respond to particular circumstances that may arise during the Round with the objective of reducing Energy Portfolio Prices. If, during a Round, the Representatives of EESI and PICA do not agree on a particular modification, the Round will continue without the modification.

7.3 Certification following Round

Within 2 business days following the completion of each Round, EESI will prepare and circulate to the Representative of PICA and the Advisor, a Certification of Compliance for that Round certifying that EESI has carried out that Round in compliance with the requirements of this 2004/2005 Plan. Unless the Representatives of EESI and PICA agree to proceed, a subsequent Round will not be initiated until the respective Representatives of EESI, PICA and the Advisor, who were present at the Round, have signed the Certification of Compliance for the Round.

7.4 Consultation Process between Rounds

Representatives of EESI and PICA will meet with the Advisor within 2 business days or such other time as they may agree following the end of each Round. The Representatives and the Advisor will review the results of the Round and any market developments or trends that any party may reasonably believe will have a material impact on the continued implementation of the 2004/2005 Plan. This could include, but is not limited, to significant changes in market prices or EESI RRT Transition Rate load requirement. At the request of either party, EESI and PICA will work in good faith to identify any improvements that can be made to the Protocol taking into account the matters discussed above. EESI and PICA will work diligently to agree on any amendments to the Protocol that may be necessary to implement the identified improvements.

7.5 Dispute Resolution

(a) If the Representatives of EESI and PICA are unable to agree pursuant to Section 7.4 as to whether any improvements need to be made to the Protocol or on any amendments necessary to implement any identified improvement, subject to Section 7.5(k), either EESI or PICA (**Disputing Party**) may at any time invoke the dispute resolution process (**Dispute Resolution Process**) under this Section 7.5 by providing a written notice (**Dispute Notice**) to the other party, the Advisor and the Board Observer. The Dispute Notice must:

(i) identify the specific change that is proposed (**Proposed Change**) and the impact the Proposed Change would reasonably be expected to have on RRT rates, if any; and

(ii) identify the reason for the Proposed Change and the harm that would reasonably be expected to occur if the Proposed Change is not made.

(b) The Representatives of EESI and PICA, the Advisor and the Board Observer will use their best efforts to meet to discuss the Proposed Change within 2 business days of the Dispute Notice being provided. At that meeting, the Disputing Party invoking the Dispute Resolution Process shall cooperate fully by answering any questions the other party (**Other Party**), the Advisor or the Board Observer may have respecting the Proposed Change and the Representatives of EESI and PICA will work diligently and in good faith to reach agreement concerning the Proposed Change.

(c) If no agreement is reached at the meeting provided for under section 7.5(b), the Disputing Party must provide written notice (**Election Notice**) to the Other Party, the Advisor and the Board Observer within 1 business day of the conclusion of the meeting if it wishes to continue the Dispute Resolution Process.

(d) If the Disputing Party elects to continue the Dispute Resolution Process pursuant to Section 7.5(c), the Other Party may provide written notice (**Continuation Notice**) to the Disputing Party within 1 business day of receiving the Election Notice advising the Disputing Party whether it agrees to continue the Dispute Resolution Process.

(e) If the Disputing Party does not provide the Election Notice as provided under section 7.5(c), or if the Other Party provides a Continuation Notice advising that it does not agree to continue the Dispute Resolution Process or does not provide the Continuation Notice as provided under section 7.5(d), the Disputing Party will be free to pursue the Proposed Change with the AEUB provided that the Disputing Party must ask the AEUB to decide the matter on an expedited basis and respect the confidential nature of the matters to be addressed to the extent permitted under the AEUB's rules of practice.

(f) If the Other Party agrees to continue the Dispute Resolution Process under Section 7.5(d), then both the Disputing Party and the Other Party will submit a "Final Proposal" (**Final Proposal**) in respect of the matters addressed in the Dispute Notice, to each other, the Advisor and the Board Observer within 1 business day of the Continuation Notice being provided. Any Final Proposal submitted must include the information required to be included in the Dispute Notice. If a party elects not to provide a Final Proposal within the allowed time, the Advisor and the Board Observer will proceed to resolve the matter based on the Final Proposal provided by the other party.

(g) After considering the Final Proposal(s) submitted, the Advisor and the Board Observer must, within 2 business days of the Final Proposal(s) being submitted, select one of the following options:

(i) Decide that no change should be made to the 2004/2005 Plan;

(ii) Decide in favour of EESI's Final Proposal, if submitted; or

(iii) Decide in favour of PICA's Final Proposal, if submitted

The Advisor and Board Observer will select the option that is most consistent with the intent of the parties as reflected in the 2004/2005 Plan.

(h) If the Advisor and Board Observer both select either EESI's or PICA's Final Proposal, then the 2004/2005 Plan will be amended in accordance with that Final Proposal. If both the Advisor and the Board Observer both decide that no change should be made to the 2004/2005 Plan, then no changes will be made to the 2004/2005 Plan. If the Advisor and the Board Observer select different Final Proposals, then no change will be made to the 2004/2005 Plan.

(i) The decision of the Advisor and the Board Observer under Section 7.5(h) concerning the Proposed Changes to the 2004/2005 Plan is final and binding on both EESI and PICA and may not be appealed by either party to the AEUB.

(j) All of the material provided by a party and positions taken by a party throughout the Dispute Resolution Process are confidential and may not be disclosed by any other party without the written consent of that party.

(k) The Dispute Resolution Process may not be initiated once a Round has commenced. Unless the Representatives of EESI and PICA agree to proceed, no Rounds will be initiated while a Dispute Resolution Process is underway.

8. Costs

Costs incurred by EESI and PICA in relation to the Non-RCC 2004/2005 Plan including, costs related to any dispute resolution matter, whether before the AEUB or Board Observer and Advisor, and the costs of the Advisor and AEUB administration costs will be included in the energy costs for EESI's RRT Transition Rate Non-RCC.

Schedule A
to the Non-Rate Classification Customer 2004 and 2005 Energy Price Setting Plan
dated November 18, 2003

DEFINITIONS

1. General Definitions

In the Non-Rate Classification Customer 2004 and 2005 Energy Price Setting Plan (Non-RCC **2004/2005 Plan**),

Advisor means an independent expert retained by EESI **NTD:** to provide advice and assistance as provided in the Non-RCC 2004/2005 Plan;

AEUB means the Alberta Energy and Utilities Board;

Board Observer means the individual designated by the AEUB to observe and assist as provided in the Non-RCC 2004/2005 Plan;

CCA means the Consumers Coalition of Alberta;

Certification of Compliance means, (i) in relation to a RFO Round, a certification that EESI has carried out that RFO Round in compliance with the requirements of the Non-RCC 2004/2005 Plan, in the form of the Certification of Compliance attached as Schedule "E" to the Non-RCC 2004/2005 Plan, with such modifications as may be necessary to reflect the particular details of that RFO Round, and (ii) in relation to Inter-Round Procurement, a certification that EESI has carried out the Inter-Round Procurement in compliance with the Non-RCC 2004/2005 Plan, in the form of the Certification of Compliance attached as Schedule "F" to the Non-RCC 2004/2005 Plan.

EDI Service Area means the service area of EPCOR Distribution Inc. in Alberta;

EMC means EPCOR Merchant & Capital L.P.;

EUI means EPCOR Utilities Inc.;

Exchanges means (i) the online internet trading systems for electrical energy in Alberta operated by Alberta Watt Exchange Ltd., and (ii) NGX Canada Inc.;

Inter-Round Procurement means an Inter-Round process, administered by the Advisor, conducted in accordance with the Inter-Round Protocol;

Method means, the energy price setting method set out in the Non-RCC 2004/2005 Plan;

Monthly Product Schedule means, in relation to a Quarter, a schedule for the Quarter in the applicable form attached as Schedule "C" to the Non-RCC 2004/2005 Plan setting out, among other things, the Total RRT Transition Rate Volumes, Total RRT Transition

Rate Target Volume, EESI RRT Transition Rate Non-RCC Volumes and EESI RRT Transition Rate Non-RCC Volume Percentage, the Forecast Peak Load Portion for EESI's RRT Transition Rate Non-RCC for that Quarter, the NRCFPLP for each EESI RRT Transition Rate Non-RCC for the Quarter and the forecast energy consumption at the customer meter for each EESI RRT Transition Rate Non-RCC for the Quarter;

PICA means the Public Institutional Consumers of Alberta;

Protocol means the RFO Protocol;

Q1 means January, February and March of 2004 or 2005;

Q2 means April, May and June of 2004 or 2005;

Q3 means July, August and September of 2004 or 2005;

Q4 means October, November and December of 2004 or 2005;

Quarters means Q1, Q2, Q3 and Q4 and **Quarter** means any of Q1, Q2, Q3 or Q4;

RFO means, in relation to a Product, a request for an offer made by EESI to a Qualified Supplier for supplies of that Product;

RFO Protocol means the Protocol for RFO Round attached as Schedule "D" to the 2004/2005 Plan;

RFO Round means a RFO process, administered by the Advisor, conducted in accordance with the RFO Protocol;

Round means a RFO Round;

RRT means a regulated rate tariff as contemplated under section 103 of the Electric Utilities Act S.A. 2003, c. E-5.1;

RRT Transition Rate means a regulated rate tariff for eligible customers approved by the AEUB under the section 103 of the Electric Utilities Act S.A. 2003, c. E-5.1;

RRT Transition Rate Customers means the customers of EESI receiving RRT Transition Rate service,

Target Volume means, in relation to a Round, the amount of Product targeted to be acquired in that Round.

2. Product Definitions

In the 2004/ 2005 Plan,

Base Period means the period from 00:00 hours to 24:00 hours, Monday through Sunday inclusive;

Base Product means an agreement to supply power twenty-four hours a day, seven days a week and may include a Monthly Base Product and a One-Year Base Product;

Monthly Product means a Monthly Base Product, a Monthly Peak Product or a Monthly Off-Peak Product;

Monthly Base Product means a Base Product having a one-month term;

Monthly Off-Peak Product means a Monthly Off-Peak (7x8) Product, or a Monthly Super Off-Peak (7x18) Product having a one-month term

Monthly Off-Peak (7x8) Product means an Off-Peak (7x8) Product having a one-month term;

Monthly Super Off-Peak (7x18) Product means a Super Off-Peak (7x18) Product having a one-month term;

Monthly Peak Product means a Monthly Peak (7x16) Product, or a Monthly Super Peak (7x6) Product;

Monthly Peak (7x16) Product means a Peak (7x16) Product having a one-month term;

Monthly Super Peak (7x6) Product means a Super Peak (7x6) Product having a one-month term;

Off-Peak (7x8) Period means the period from 0:00 hours to 7:00 hours and from 23:00 hours to 0:00 hours, Monday through Sunday inclusive;

Off-Peak Periods means Off-Peak (7x8) Periods, Super Off-Peak (7x18) Periods and

Off-Peak Period means any of Off-Peak (7x8) Period, or Super Off-Peak (7x18) Period as the context may require.

Off-Peak Product means an agreement to supply power during an Off-Peak Period and may include a Monthly Off-Peak Product and/or a One-Year Off-Peak Product;

Off-Peak (7x8) Product means an agreement to supply power during a Peak (7x8) Period;

One-Year Product means a One-Year Base Product, a One-Year Peak Product or a One-Year Off-Peak Product;

One-Year Base Product means a Base Product having a one-year term;

One-Year Off-Peak Product means a One-Year Off-Peak (7x8) Product;

One-Year Off-Peak (7x8) Product means an Off-Peak (7x8) Product having a one-year term;

One-Year Peak Product means a One-Year Peak (7x16) Product;

One-Year Peak (7x16) Product means a Peak (7x16) Product having a one-year term;

Peak (7x16) Period means the period from 7:00 hours to 23:00 hours, Monday through Sunday inclusive;

Peak Periods means Peak (7x16) Periods, Super Peak (7x6) Periods and **Peak Period** means either of a Peak (7x16) Period, or Super Peak (7x6) Period as the context may require;

Peak Product means an agreement to supply power during a Peak Period and may include a Monthly Peak Product and/or a One-Year Peak Product;

Peak (7x16) Product means an agreement to supply power during a Peak (7x16) Period;

Product means a Base Product, a Peak Product or an Off-Peak Product;

Quarterly Base Product means a Base Product having a one Quarter term;

Quarterly Off-Peak Product means a Quarterly Off-Peak (7x8) Product;

Quarterly Off-Peak (7x8) Product means an Off-Peak (7x8) Product having a one-Quarter term;

Quarterly Product means a Quarterly Base Product, a Quarterly Peak Product, or a Quarterly Off-Peak Product;

Quarterly Peak Product means a Quarterly Peak (7x16) Product;

Quarterly Peak (7x16) Product means a Peak (7x16) Product having a one-Quarter term;

Quarterly Product means a Quarterly Base Product or a Quarterly Peak Product;

Shoulder Peak Period means a Peak Period excluding the Super Peak Period portion of the Peak Period;

Super Off-Peak (7x18) Period means the period from 0:00 hours to 16:00 hours and 22:00 hours to 0:00 hours, Monday through Sunday inclusive;

Super Off-Peak (7x18) Product means an agreement to supply power during a Super Off-Peak (7x18) Period;

Super Peak (7x6) Period means the period from 16:00 hours to 22:00 hours, Monday through Sunday inclusive, including holidays.

Super Peak (7x6) Product means an agreement to supply power during a Super Peak (7x6) Period;

3. **Price, Volume and Portfolio Definitions**

In the Non-RCC 2004/2005 Plan,

Base Energy Portfolio Price means, for a Quarter, the average price (weighted by volume) of the Base Products in the Energy Product Portfolio for that period, expressed in $/MWh;

EESI RRT Transition Rate Classification has the meaning given to that term in the EESI RRT Transition Rate Price Schedule.

EESI RRT Transition Rate Non-RCC Volumes means (i) in relation to One-Year Products for a year, EESI's reasonable forecast of the total volume of One-Year Base Products and One-Year Peak Products required (with separate procurement) for its RRT Transition Rate Non-RCC in the EDI Service Area as set out in Table 1 of Schedule "B" to the Non-RCC 2004/2005 Plan and (ii) in relation to Monthly Products, EESI's reasonable forecast of the volume of Monthly Base Products and Monthly Peak Products required (with separate procurement) for its RRT Transition Rate Non-RCC in the EDO Service Area for a month, as set out in the Monthly Product Schedule for the Quarter in which that month occurs.

EESI RRT Transition Rate Non-RCC Volume Percentage means (i) in relation to One-Year Products for a year, EESI's reasonable forecast of the total volume of One-Year Base Products and One-Year Peak Products required (with separate procurement) for its RRT Transition Rate Non-RCC in the EDI Service Area relative to the total volume of One-Year Base Products and One-Year Peak Products required (with separate procurement) for RRT Transition Rate Non-RCC as set out in Table 1 of Schedule "B" to the Non-RCC 2004/2005 Plan and (ii) in relation to Monthly Products, EESI's reasonable forecast of the volume of Monthly Base Products and Monthly Peak Products required (with separate procurement) for its RRT Transition Rate Non-RCC in the EDI Service Area for a month relative to the total volume of Monthly Base Products and Monthly Peak Products required (with separate procurement) for RRT Transition Rate Non-RCC as set out in the Monthly Product Schedule for the Quarter in which that month occurs.

Energy Portfolio Prices means, for a Quarter, the Base Energy Portfolio Price, the Off Peak Energy Portfolio Price and the Peak Energy Portfolio Price for that period;

Energy Product Portfolio means, at a point in time, the portfolio of Base Products and Peak Products that have then been acquired or deemed to have been acquired for the

Energy Product Portfolio pursuant to the 2001 Plan, and the Non-RCC 2004/2005 Plan and the terms of which have not expired at that time;

Forecast Price means, in relation to a Monthly Product for the second or third month of a Quarter:

(i) the price of an offer (if any) or, if there are more than one, the simple average of the prices of offers for volumes of at least 5MW of the energy product corresponding to the Monthly Product recorded, during the last Round conducted to acquire the Monthly Product for the first month of the Quarter, from the Exchange Screens (as defined in the applicable Protocol) at the time the indicative Heat Rate is being determined under Step 2 of the RFO Round Protocol; or

(ii) if the price referred to in (i) of this definition is not available, the last transacted price (if any) or, it there is more than one, the simple average of the last transacted prices for volumes of at least 5MW of the energy product corresponding to the Monthly Product obtained from the Exchanges (as defined in the applicable Protocol) at the time referred to in (i) of this definition; or

(iii) if prices referred to in (i) and (ii) of this definition are not available and the Quarter is:

(A) the first, second or third Quarter, EESI will propose a price for the Monthly Product to the representative of PICA and they will work diligently and in good faith to agree on the price and the Forecast Price for the Monthly Product will be the agreed price or, failing agreement within two business days, the actual price for the Monthly Product acquired for the first month of the Quarter; or

(B) the fourth Quarter, the Forecast Price for the Monthly Product will be the Proposed Monthly Product Price or, when available, the Monthly Product Price established as provided below in this definition.

If (iii)(B) of this definition applies, EESI will propose a price for the Monthly Product (**Proposed Monthly Product Price**) to the representative of PICA. If the representative of PICA does not agree with the Proposed Monthly Product Price, the parties will work diligently and in good faith with each other and the Advisor to reach agreement. Either EESI or the representative of PICA may at any time invoke the Dispute Resolution Process under Section 7.5 of the 2004/ 2005 Plan by providing a Dispute Notice to the other party. The price agreed on by EESI and PICA or determined pursuant to the Dispute Resolution Process (**Monthly Product Price**) will be the Forecast Price for the Monthly Product. Pending agreement or determination of the Monthly Product Price, the Proposed Monthly Product Price will be used for the purposes of the Section 5 of the Energy Price Setting Plan.

Forecast Peak Load Portion (FPLP) means, in relation to a Quarter, the value set out in Table 1d of the Monthly Product Schedule for that Quarter.

Off-Peak Energy Portfolio Cost means, for a period, the amount determined by subtracting the Peak Energy Portfolio Cost from the Total Energy Portfolio Cost for that period.

Off-Peak Energy Portfolio Price means, for a Quarter, the amount determined as follows:

$$OPEPP = OPEPC/[TEPV \times (1 - FPLP)]$$

where:

OPEPP is the Off-Peak Energy Portfolio Price for that Quarter, expressed in $/MWh;

OPEPC is the Off-Peak Energy Portfolio Cost for that Quarter;

TEPV is the Total Energy Portfolio Volume for that Quarter;

FPLP is the Forecast Peak Load Portion for that Quarter;

Non-Rate Classification Forecast Peak Load Portion (NRCFPLP) means, in relation to an EESI RRT Transition Rate Non-RCC Customer for a Quarter, the value for that EESI RRT Transition Rate Non-RCC Customer set out in Table 1e of the Monthly Product Schedule for that Quarter.

Peak Energy Portfolio Cost means, for a Quarter, the amount determined as follows:

$$PEPC = TEPV \times FPLP \times PEPP$$

where:

PEPC is the Peak Energy Portfolio Cost for that Quarter, expressed in $/MWh;

TEPV is the Total Energy Portfolio Volume for that Quarter;

FPLP is the Forecast Peak Load Portion for that Quarter;

PEPP is the Peak Energy Portfolio Price for that Quarter;

Peak Energy Portfolio Price means, in the case of Q1, the Peak Energy Portfolio Price (Unadjusted) for that Quarter and in the case of each of the other Quarters, the Peak Energy Portfolio Price (Unadjusted) plus the Peak Energy Portfolio Price Adjustment for that Quarter if it is a positive amount or minus the Peak Energy Portfolio Price Adjustment for that Quarter if it is a negative amount;

Peak Energy Portfolio Price (Unadjusted) means, for a Quarter, the price for Peak Products included in the Energy Product for that Quarter which will be equal to the quotient of:

(a) the sum of:

(i) $YP(7x16)PMW_y$ x $QP(7x16)PH_Q$ x $YP(7x16)PP_y$;

(ii) $MP(7x16)PMW_{m1\text{-}for}$ x $MP(7x16)PH_{m1}$ x $MP(7x16)PP_{m1\text{-}act}$;

(iii) $MP(7x16)PMW_{m2\text{-}for}$ x $MP(7x16)PH_{m2}$ x $MP(7x16)PP_{m2\text{-}for}$;

(iv) $MP(7x16)PMW_{m3\text{-}for}$ x $MP(7x16)PH_{m3}$ x $MP(7x16)PP_{m3\text{-}for}$;

(v) $MSP(7x6)PMW_{m1\text{-}for}$ x $MSP(7x6)PH_{m1}$ x $MSP(7x6)PP_{m1\text{-}act}$;

(vi) $MSP(7x6)PMW_{m2\text{-}for}$ x $MSP(7x6)PH_{m2}$ x $MSP(7x6)PP_{m2\text{-}for}$;

(vii) $MSP(7x6)PMW_{m3\text{-}for}$ x $MSP(7x6)PH_{m3}$ x $MSP(7x6)PP_{m3\text{-}for}$; and

(viii) $QP(7x16)PMWq$ x $QP(7x16)PH_Q$ x $QP(7x16)PP_Q$;

divided by;

(b) the sum of:

(i) $YP(7x16)PMW_y$ x $QP(7x16)PH_Q$;

(ii) $MP(7x16)PMW_{m1\text{-}for}$ x $MP(7x16)PH_{m1}$;

(iii) $MP(7x16)PMW_{m2\text{-}for}$ x $MP(7x16)PH_{m2}$;

(iv) $MP(7x16)PMW_{m3\text{-}for}$ x $MP(7x16)PH_{m3}$;

(v) $MSP(7x6)PMW_{m1\text{-}for}$ x $MSP(7x6)PH_{m1}$;

(vi) $MSP(7x6)PMW_{m2\text{-}for}$ x $MSP(7x6)PH_{m2}$;

(vii) $MSP(7x6)PMW_{m3\text{-}for}$ x $MSP(7x6)PH_{m3}$; and,

(viii) $QP(7x16)PMW_Q$ x $QP(7x16)PH_Q$;

where:

$YP(7x16)PMW_y$ is the total capacity of One-Year Peak (7x16) Products, expressed in MWs, acquired for the Energy Product Portfolio for 2004or 2005

QP(7x16)PH$_Q$ is the total number of hours in Peak (7x16) Periods that occur in that Quarter;

YP(7x16)PP$_y$ is the average (weighted by capacity acquired) of the prices of the One Year Peak (7x16) Products acquired for the Energy Product Portfolio for 2004 or 2005;

MP(7x16)PMW$_{m1\text{-}for}$ is the total capacity of Monthly Peak (7x16) Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the first month of that Quarter;

MP(7x16)PH$_{m1}$ is the total number of hours in Peak (7x16) Periods that occur in the first month of that Quarter;

MP(7x16)PP$_{m1\text{-}act}$ is the average (weighted by capacity acquired) of the prices of the Monthly Peak (7x16) Products acquired for the Energy Product Portfolio for the first month of that Quarter;

MP(7x16)PMW$_{m2\text{-}for}$ is the total capacity of Monthly Peak (7x16) Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the second month of that Quarter;

MP(7x16)PH$_{m2}$ is the total number of hours in Peak (7x16) Periods that occur in the second month of that Quarter;

MP(7x16)PP$_{m2\text{-}for}$ is the Forecast Price of the Monthly Peak (7x16) Products to be acquired for the Energy Product Portfolio for the second month of that Quarter;

MP(7x16)PMW$_{m3\text{-}for}$ is the total capacity of Monthly Peak (7x16) Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the third month of that Quarter;

MP(7x16)PH$_{m3}$ is the total number of hours in Peak (7x16) Periods that occur in the third month of that Quarter;

MP(7x16)PP$_{m3\text{-}for}$ is the Forecast Price of the Monthly Peak (7x16) Products to be acquired for the Energy Product Portfolio for the third month of that Quarter;

MSP(7x6)PMW$_{m1\text{-}for}$ is the total capacity of Monthly Super Peak (7x6) Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the first month of that Quarter;

MSP(7x6)PH$_{m1}$ is the total number of hours in Super Peak (7x6) Periods that occur in the first month of that Quarter;

MSP(7x6)PP$_{m1\text{-}act}$ is the average price (weighted by capacity purchased) of the Monthly Super Peak (7x6) Products acquired for the Energy Product Portfolio for the first month of that Quarter;

MSP(7x6)PMW$_{m2\text{-}for}$ is the total capacity of Monthly Super Peak (7x6) Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the second month of that Quarter;

MSP(7x6)PH$_{m2}$ is the total number of hours in Super Peak (7x6) Periods that occur in the second month of that Quarter;

MSP(7x6)PP$_{m2\text{-}for}$ is the Forecast Price of the Monthly Super Peak (7x6) Products to be acquired for the Energy Product Portfolio for the second month of that Quarter;

MSP(7x6)PMW$_{m3\text{-}for}$ is the total capacity of Monthly Super Peak (7x6) Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the third month of that Quarter;

MSP(7x6)PH$_{m3}$ is the total number of hours in Super Peak (7x6) Periods that occur in the third month of that Quarter;

MSP(7x6)PP$_{m3\text{-}for}$ is the Forecast Price of the Monthly Super Peak (7x6) Products to be acquired for the Energy Product Portfolio for the third month of that Quarter;

QP(7x16)PMW$_{Q}$ is the total capacity of Quarterly Peak (7x16) Products, expressed in MWs, acquired for the Energy Product Portfolio for that Quarter;

QP(7x16)PP$_{Q}$ is the average (weighted by capacity acquired) of the prices of the Quarterly Peak (7x16) Products acquired for the Energy Product Portfolio for that Quarter;

Peak Energy Portfolio Price Adjustment means, for a Quarter, the positive or negative adjustment to the Peak Energy Portfolio Price (Unadjusted) for that Quarter for the actual prices of Monthly Peak Products acquired for the Energy Product Portfolio for the second and third months of the immediately preceding Quarter which will be a positive or negative amount equal to the quotient of:

(a) the sum of:

(i) $MP(7x16)PMW_{m2(Q-1)\text{-}for} \times MP(7x16)PH_{m2(Q-1)} \times (MP(7x16)PP_{m2(Q-1)\text{-}act} - MP(7x16)PP_{m2(Q-1)\text{-}for})$;

(ii) $MP(7x16)PMW_{m3(Q-1)\text{-}for} \times MP(7x16)PH_{m3(Q-1)} \times (MP(7x16)PP_{m3(Q-1)\text{-}act} - MP(7x16)PP_{m3(Q-1)\text{-}for})$;

(iii) $MSP(7x6)PMW_{m2(Q-1)\text{-}for} \times MSP(7x6)PH_{m2(Q-1)} \times (MSP(7x6)PP_{m2(Q-1)\text{-}act} - MSP(7x6)PP_{m2(Q-1)\text{-}for})$

(iv) $MSP(7x6)PMW_{m3(Q-1)\text{-}for} \times MSP(7x6)PH_{m3(Q-1)} \times (MSP(7x6)PP_{m3(Q-1)\text{-}act} - MSP(7x6)PP_{m3(Q-1)\text{-}for})$;

divided by;

(b) the sum of:

(i) $YP(7x16)PMW_y \times QP(7x16)PH_Q$;

(ii) $MP(7x16)PMW_{m1\text{-}for} \times MP(7x16)PH_{m1}$;

(iii) $MP(7x16)PMW_{m2\text{-}for} \times MP(7x16)PH_{m2}$;

(iv) $MP(7x16)PMW_{m3\text{-}for} \times MP(7x16)PH_{m3}$;

(v) $MSP(7x6)PMW_{m1\text{-}for} \times MSP(7x6)PH_{m1}$;

(vi) $MSP(7x6)PMW_{m2\text{-}for} \times MSP(7x6)PH_{m2}$;

(vii) $MSP(7x6)PMW_{m3\text{-}for} \times MSP(7x6)PH_{m3}$;

(viii) $QP(7x16)PMW_Q \times QP(7x16)PH_Q$;

where:

$YP(7x16)PMW_y$ is the total capacity of One-Year Peak (7x16) Products, expressed in MWs, acquired for the Energy Product Portfolio for 2004 and 2005;

$QP(7x16)PH_Q$ is the total number of hours in Peak (7x16) Periods that occur in the Quarter for which the Peak Energy Portfolio Price Adjustment is being determined;

$MP(7x16)PMW_{m2(Q-1)\text{-}for}$ is the total capacity of Monthly Peak (7x16) Products, expressed in MWs, forecast in the Monthly Product Schedule for the immediately preceding Quarter to be acquired for the Energy Product Portfolio for the second month of that Quarter;

$MP(7x16)PH_{m2(Q-1)}$ is the total number of hours in Peak (7x16) Periods that occur in the second month of the immediately preceding Quarter;

$MP(7x16)PP_{m2(Q-1)\text{-}act}$ is the average (weighted by capacity acquired) of the prices of the Monthly Peak (7x16) Products to be acquired for the Energy Product Portfolio for the second month of the immediately preceding Quarter;

$MP(7x16)PP_{m2(Q-1)\text{-}for}$ is the Forecast Price of the Monthly Peak (7x16) Products to be acquired for the Energy Product Portfolio for the second month of the immediately preceding Quarter;

MP(7x16)PMW$_{m3(Q-1)-for}$ is the total capacity of Monthly Peak (7x16) Products, expressed in MWs, forecast in the Monthly Product Schedule for the immediately preceding Quarter to be acquired for the Energy Product Portfolio for the third month of that Quarter;

MP(7x16)PH$_{m3(Q-1)}$ is the total number of hours in Peak (7x16) Periods that occur in the third month of the immediately preceding Quarter;

MP(7x16)PP$_{m3(Q-1)-act}$ is the average (weighted by capacity acquired) of the prices of the Monthly Peak (7x16) Products acquired for the Energy Product Portfolio for the third month of the immediately preceding Quarter;

MP(7x16)PP$_{m3(Q-1)-for}$ is the Forecast Price of the Monthly Peak (6x16) Products to be acquired for the Energy Product Portfolio for the third month of the immediately preceding Quarter;

MSP(7x6)PH$_{Q}$ is the total number of hours in Super Peak (7x6) Periods that occur in the Quarter for which the Peak Energy Portfolio Price Adjustment is being determined;

MSP(7x6)PMW$_{m2(Q-1)-for}$ is the total capacity of Monthly Super Peak (7x6) Products, expressed in MWs, forecast in the Monthly Product Schedule for the immediately preceding Quarter to be acquired for the Energy Product Portfolio for the second month of that Quarter;

MSP(7x6)PH $_{m2(Q-1)}$ is the total number of hours in Super Peak (7x6) Periods that occur in the second month of the immediately preceding Quarter;

MSP(7x6)PP$_{m2(Q-1)-act}$ is the average (weighted by capacity acquired) of the prices of the Monthly Super Peak (7x6) Products acquired for the Energy Product Portfolio for the second month of the immediately preceding Quarter;

MSP(7x6)PP$_{m2(Q-1)-for}$ is the Forecast Price of the Monthly Super Peak (7x6) Products to be acquired for the Energy Product Portfolio for the second month of the immediately preceding Quarter;

MSP(7x6)PMW$_{m3(Q-1)-for}$ is the total capacity of Monthly Super Peak (7x6) Products, expressed in MWs, forecast in the Monthly Product Schedule for the immediately preceding month to be acquired for the Energy Product Portfolio for the third month of that Quarter;

MSP(7x6)PH $_{m3(Q-1)}$ is the total number of hours in Super Peak (7x6) Periods that occur in the third month of the immediately preceding Quarter;

MSP(7x6)PP$_{m3(Q-1)-act}$ is the average (weighted by capacity acquired) of the prices of the Monthly Super Peak (7x6) Products acquired for the Energy Product Portfolio for the third month of the immediately preceding Quarter;

$MSP(7x6)PP_{m3(Q-1)-for}$ is the Forecast Price of the Monthly Super Peak (7x6) Products to be acquired for the Energy Product Portfolio for the third month of the immediately preceding Quarter;

$MP(7x16)PMW_{m1-for}$ is the total capacity of Monthly Peak (7x16) Products, expressed in MWs, forecast in the Monthly Product Schedule for the Quarter for which the Peak Energy Portfolio Price Adjustment is being determined to be acquired for the Energy Product Portfolio for the first month of that Quarter;

$MP(7x16)PH_{m1}$ is the total number of hours in Peak (7x16) Periods that occur in the first month of the Quarter for which the Peak Energy Portfolio Price Adjustment is being determined;

$MP(7x16)PMW_{m2-for}$ is the total capacity of Monthly Peak (7x16) Products, expressed in MWs, forecast in the Monthly Product Schedule for the Quarter for which the Peak Energy Portfolio Price Adjustment is being determined to be acquired for the Energy Product Portfolio for the second month of that Quarter;

$MP(7x16)PH_{m2}$ is the total number of hours in Peak (7x16) Periods that occur in the second month of the Quarter for which the Peak Energy Portfolio Price Adjustment is being determined;

$MP(7x16)PMW_{m3-for}$ is the total capacity of Monthly Peak (7x16) Products, expressed in MWs, forecast in the Forecast for the Quarter for which the Peak Energy Portfolio Price Adjustment is being determined to be acquired for the Energy Product Portfolio for the third month of that Quarter;

$MP(7x16)PH_{m3}$ is the total number of hours in Peak (7x16) Periods that occur in the third month of the Quarter for which the Peak Energy Portfolio Price Adjustment is being determined;

$QP(7x16)PMW_{y}$ is the total capacity of Quarterly Peak (7x16) Products, expressed in MWs, acquired for the Energy Product Portfolio for the Quarter for which the Peak Energy Portfolio Price Adjustment is being determined;

Product Ratio means an agreed upon ratio of Peak Product or Super Peak Product to Base Product as determined in accordance with Schedule B or C for an RFO Round, that if exceeded, the representative of PICA will have an option to purchase the next Product closest to (or including) Base Product (i.e. Peak Product as a replacement for Super Peak Product or Base Product as a replacement for Peak Product).

Threshold Price means an agreed upon price, as determined in either Schedule B or C (as applicable), that if exceeded, the representative of PICA will have an option of requesting that EESI not purchase the required Product volumes in an RFO Round.

Total Energy Portfolio Cost (Unadjusted) means, for a Quarter, the amount equal to the sum of:

(i) $YBPMW_y \times QBPH_Q \times YBPP_y$;

(ii) $MBPMW_{m1\text{-}for} \times MBPH_{m1} \times MBPP_{m1\text{-}act}$;

(iii) $MBPMW_{m2\text{-}for} \times MBPH_{m2} \times MBPP_{m2\text{-}for}$;

(iv) $MBPMW_{m3\text{-}for} \times MBPH_{m3} \times MBPP_{m3\text{-}for}$;

(v) $YP(7x16)PMW_y \times QP(7x16)PH_Q \times YP(7x16)PP_y$;

(vi) $MP(7x16)PMW_{m1\text{-}for} \times MP(7x16)PH_{m1} \times MP(7x16)PP_{m1\text{-}act}$;

(vii) $MP(7x16)PMW_{m2\text{-}for} \times MP(7x16)PH_{m2} \times MP(7x16)PP_{m2\text{-}for}$;

(viii) $MP(7x16)PMW_{m3\text{-}for} \times MP(7x16)PH_{m3} \times MP(7x16)PP_{m3\text{-}for}$;

(ix) $MSP(7x6)PMW_{m1\text{-}for} \times MSP(7x6)PH_{m1} \times MSP(7x6)PP_{m1\text{-}act}$;

(x) $MSP(7x6)PMW_{m2\text{-}for} \times MSP(7x6)PH_{m2} \times MSP(7x6)PP_{m2\text{-}for}$;

(xi) $MSP(7x6)PMW_{m3\text{-}for} \times MSP(7x6)PH_{m3} \times MSP(7x6)PP_{m3\text{-}for}$;

(xii) $QBPMW_Q \times QBPH_Q \times QBPP_Q$; and

(xiii) $QP(7x16)PMW_Q \times QP(7x16)PH_Q \times QP(7x16)PP_Q$;

where:

$YBPMW_y$ is the total capacity of One-Year Base Products, expressed in MWs, acquired for the Energy Product Portfolio for 2004 or 2005;

$QBPH_Q$ is the total number of hours in Base Periods that occur in that Quarter;

$YBPP_y$ is the average (weighted by capacity acquired) of the prices of the One Year Base Products acquired for the Energy Product Portfolio for 2004 or 2005;

$MBPMW_{m1\text{-}for}$ is the total capacity of Monthly Base Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the first month of that Quarter;

$MBPH_{m1}$ is the total number of hours in Base Periods that occur in the first month of that Quarter;

$MBPP_{m1\text{-}act}$ is the average (weighted by capacity acquired) of the prices of the Monthly Base Products acquired for the Energy Product Portfolio for the first month of that Quarter;

$MBPMW_{m2\text{-}for}$ is the total capacity of Monthly Base Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the second month of that Quarter;

$MBPH_{m2}$ is the total number of hours in Base Periods that occur in the second month of that Quarter;

$MBPP_{m2\text{-}for}$ is the Forecast Price of the Monthly Base Products to be acquired for the Energy Product Portfolio for the second month of that Quarter;

$MBPMW_{m3\text{-}for}$ is the total capacity of Monthly Base Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the third month of that Quarter;

$MBPH_{m3}$ is the total number of hours in Base Periods that occur in the third month of that Quarter;

$MBPP_{m3\text{-}for}$ is the Forecast Price of the Monthly Base Products to be acquired for the Energy Product Portfolio for the third month of that Quarter;

$YP(7x16)PMW_y$ is the total capacity of One-Year Peak (7x16) Products, expressed in MWs, acquired for the Energy Product Portfolio for 2004or 2005;

$QP(7x16)PH_Q$ is the total number of hours in Peak (7x16) Periods that occur in that Quarter;

$YP(7x16)PP_y$ is the average (weighted by capacity acquired) of the prices of the One Year Peak (7x16) Products acquired for the Energy Product Portfolio for 2004 or 2005;

$MP(7x16)PMW_{m1\text{-}for}$ is the total capacity of Monthly Peak (7x16) Products, expressed in MWs, forecast in the Monthly Product Schedule to that Quarter to be acquired for the Energy Product Portfolio for the first month of that Quarter;

$MP(7x16)PH_{m1}$ is the total number of hours in Peak (7x16) Periods that occur in the first month of that Quarter;

$MP(7x16)PP_{m1\text{-}act}$ is the average (weighted by capacity acquired) of the prices of the Monthly Peak (7x16) Products acquired for the Energy Product Portfolio for the first month of that Quarter;

$MP(7x16)PMW_{m2\text{-}for}$ is the total capacity of Monthly Peak (7x16) Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the second month of that Quarter;

$MP(7x16)PH_{m2}$ is the total number of hours in Peak (7x16) Periods that occur in the second month of that Quarter;

MP(7x16)PP$_{m2\text{-}for}$ is the Forecast Price of the Monthly Peak (7x16) Products to be acquired for the Energy Product Portfolio for the second month of that Quarter;

MP(7x16)PMW$_{m3\text{-}for}$ is the total capacity of Monthly Peak (7x16) Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the third month of that Quarter;

MP(7x16)PH$_{m3}$ is the total number of hours in Peak (7x16) Periods that occur in the third month of that Quarter;

MP(7x16)PP$_{m3\text{-}for}$ is the Forecast Price of the Monthly Peak (6x16) Products to be acquired for the Energy Product Portfolio for the third month of that Quarter;

MSP(7x6)PMW$_{m1\text{-}for}$ is the total capacity of Monthly Super Peak (7x6) Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the first month of that Quarter;

MSP(7x6)PH$_{m1}$ is the total number of hours in Super Peak (7x6) Periods that occur in the first month of that Quarter;

MSP(7x6)PP$_{m1\text{-}act}$ is the average price (weighted by capacity purchased) of the Monthly Super Peak (7x6) Products acquired for the Energy Product Portfolio for the first month of that Quarter;

MSP(7x6)PMW$_{m2\text{-}for}$ is the total capacity of Monthly Super Peak (7x6) Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio I for the second month of that Quarter;

MSP(7x6)PH$_{m2}$ is the total number of hours in Super Peak (7x6) Periods that occur in the second month of that Quarter;

MSP(7x6)PP$_{m2\text{-}for}$ is the Forecast Price of the Monthly Super Peak (7x6) Products to be acquired for the Energy Product Portfolio for the second month of that Quarter;

MSP(7x6)PMW$_{m3\text{-}for}$ is the total capacity of Monthly Super Peak (7x6) Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the third month of that Quarter;

MSP(7x6)PH$_{m3}$ is the total number of hours in Super Peak (7x6) Periods that occur in the third month of that Quarter;

MSP(7x6)PP$_{m3\text{-}for}$ is the Forecast Price of the Monthly Super Peak (7x6) Products to be acquired for the Energy Product Portfolio for the third month of that Quarter;

$QBPMW_Q$ is the total capacity of Quarterly Base Products, expressed in MWs, acquired for the Energy Product Portfolio for that Quarter;

$QP(7x16)PMW_Q$ is the total capacity of Quarterly Peak (7x16) Products, expressed in MWs, acquired for the Energy Product Portfolio for that Quarter;

$QP(7x16)PP_Q$ is the average (weighted by capacity acquired) of the prices of the Quarterly Peak (7x16) Products acquired for the Energy Product Portfolio for that Quarter;

Total Energy Portfolio Cost Adjustment means, for a Quarter, the positive or negative adjustment to the Total Energy Portfolio Cost (Unadjusted) for that Quarter for the actual prices of Monthly Products acquired for the Energy Product Portfolio for the second and third months of the immediately preceding Quarter which will be a positive or negative amount equal to the sum of:

(i) $MBPMW_{m2(Q-1)\text{-}for} \times MBPH_{m2(Q-1)} \times (MBPP_{m2(Q-1)\text{-}act} - MBPP_{m2(Q-1)\text{-}for})$;

(ii) $MBPMW_{m3(Q-1)\text{-}for} \times MBPH_{m3(Q-1)} \times (MBPP_{m3(Q-1)\text{-}act} - MBPP_{m3(Q-1)\text{-}for})$;

(iii) $MP(7x16)PMW_{m2(Q-1)\text{-}for} \times MP(7x16)PH_{m2(Q-1)} \times (MP(7x16)PP_{m2(Q-1)\text{-}act} - MP(7x16)PP_{m2(Q-1)\text{-}for})$;

(iv) $MP(7x16)PMW_{m3(Q-1)\text{-}for} \times MP(7x16)PH_{m3(Q-1)} \times (MP(7x16)PP_{m3(Q-1)\text{-}act} - MP(7x16)PP_{m3(Q-1)\text{-}for})$;

(v) $MSP(7x6)PMW_{m2(Q-1)\text{-}for} \times MSP(7x6)PH_{m2(Q-1)} \times (MSP(7x6)PP_{m2(Q-1)\text{-}act} - MSP(7x6)PP_{m2(Q-1)\text{-}for})$

(vi) $MSP(7x6)PMW_{m3(Q-1)\text{-}for} \times MSP(7x6)PH_{m3(Q-1)} \times (MSP(7x6)PP_{m3(Q-1)\text{-}act} - MSP(7x6)PP_{m3(Q-1)\text{-}for})$;

where:

$MBPMW_{m2(Q-1)\text{-}for}$ is the total capacity of Monthly Base Products, expressed in MWs, forecast in the Monthly Product Forecast for the immediately preceding Quarter to be acquired for the Energy Product Portfolio for the second month in that Quarter;

$MBPH_{m2(Q-1)}$ is the total number of hours in Base Periods that occur in the second month of the immediately preceding Quarter;

$MBPP_{m2(Q-1)\text{-}act}$ is the average (weighted by capacity acquired) of the prices of the Monthly Base Products acquired for the Energy Product Portfolio for the second month of the immediately preceding Quarter;

MBPP $_{m2(Q-1)\text{-}for}$ is the Forecast Price of the Monthly Base Products to be acquired for the Energy Product Portfolio for the second month of the immediately preceding Quarter;

MBPMW$_{m3(Q-1)\text{-}for}$ is the total capacity of Monthly Base Products, expressed in MWs, forecast in the Monthly Product Schedule for the immediately preceding Quarter to be acquired for the Energy Product Portfolio for the third month of that Quarter;

MBPH $_{m3(Q-1)}$ is the total number of hours in Base Periods that occur in the third month of the immediately preceding Quarter;

MBPP $_{m3(Q-1)\text{-}act}$ is the average (weighted by capacity acquired) of the prices of the Monthly Base Products acquired for the Energy Product Portfolio for the third month of the immediately preceding Quarter;

MBPP $_{m3(Q-1)\text{-}for}$ is the Forecast Price of the Monthly Base Products to be acquired for the Energy Product Portfolio for the third month of the immediately preceding Quarter;

MP(7x16)PMW$_{m2(Q-1)\text{-}for}$ is the total capacity of Monthly Peak (7x16) Products, expressed in MWs, forecast in the Monthly Product Schedule for the immediately preceding Quarter to be acquired for the Energy Product Portfolio for the second month of that Quarter;

MP(7x16)PH $_{m2(Q-1)}$ is the total number of hours in Peak (7x16) Periods that occur in the second month of the immediately preceding Quarter;

MP(7x16)PP$_{m2(Q-1)\text{-}act}$ is the average (weighted by capacity acquired) of the prices of the Monthly Peak (7x16) Products to be acquired for the Energy Product Portfolio for the second month of the immediately preceding Quarter;

MP(7x16)PP$_{m2(Q-1)\text{-}for}$ is the Forecast Price of the Monthly Peak (7x16) Products to be acquired for the Energy Product Portfolio for the second month of the immediately preceding Quarter;

MP(7x16)PMW$_{m3(Q-1)\text{-}for}$ is the total capacity of Monthly Peak (7x16) Products, expressed in MWs, forecast in the Monthly Product Schedule for the immediately preceding Quarter to be acquired for the Energy Product Portfolio for the third month of that Quarter;

MP(7x16)PH$_{m3(Q-1)}$ is the total number of hours in Peak (7x16) Periods that occur in the third month of the immediately preceding Quarter;

MP(7x16)PP$_{m3(Q-1)\text{-}act}$ is the average (weighted by capacity acquired) of the prices of the Monthly Peak (6x16) Products acquired for the Energy Product Portfolio for the third month of the immediately preceding Quarter;

MP(7x16)PP$_{m3(Q-1)\text{-}for}$ is the Forecast Price of the Monthly Peak (6x16) Products to be acquired for the Energy Product Portfolio for the third month of the immediately preceding Quarter;

MSP(7x6)PMW$_y$ is the total capacity of One-Year Super Peak (7x6) Products, expressed in MWs, acquired for the Energy Product Portfolio for 2004/ 2005

MSP(7x6)PH$_Q$ is the total number of hours in Super Peak (7x6) Periods that occur in the Quarter for which the Peak Energy Portfolio Price Adjustment is being determined;

MSP(7x6)PMW$_{m2(Q-1)\text{-}for}$ is the total capacity of Monthly Super Peak (7x6) Products, expressed in MWs, forecast in the Monthly Product Schedule for the immediately preceding Quarter to be acquired for the Energy Product Portfolio for the second month of that Quarter;

MSP(7x6)PH$_{m2(Q-1)}$ is the total number of hours in Super Peak (7x6) Periods that occur in the second month of the immediately preceding Quarter;

MSP(7x6)PP$_{m2(Q-1)\text{-}act}$ is the average (weighted by capacity acquired) of the prices of the Monthly Super Peak (7x6) Products acquired for the Energy Product Portfolio for the second month of the immediately preceding Quarter;

MSP(7x6)PP$_{m2(Q-1)\text{-}for}$ is the Forecast Price of the Monthly Super Peak (7x6) Products to be acquired for the Energy Product Portfolio for the second month of the immediately preceding Quarter;

MSP(7x6)PMW$_{m3(Q-1)\text{-}for}$ is the total capacity of Monthly Super Peak (7x6) Products, expressed in MWs, forecast in the Monthly Product Schedule for the immediately preceding month to be acquired for the Energy Product Portfolio for the third month of that Quarter;

MSP(7x6)PH$_{m3(Q-1)}$ is the total number of hours in Super Peak (7x6) Periods that occur in the third month of the immediately preceding Quarter;

MSP(7x6)PP$_{m3(Q-1)\text{-}act}$ is the average (weighted by capacity acquired) of the prices of the Monthly Super Peak (7x6) Products acquired for the Energy Product Portfolio for the third month of the immediately preceding Quarter;

MSP(7x6)PP$_{m3(Q-1)\text{-}for}$ is the Forecast Price of the Monthly Super Peak (7x6) Products to be acquired for the Energy Product Portfolio for the third month of the immediately preceding Quarter;

Total Energy Portfolio Price means, for a Quarter, the average price (weighted by volume) of the Products in the Energy Product Portfolio for that period, expressed in $/MWh;

Total Energy Portfolio Volume means, for a Quarter, the total volume of Products in the Energy Product Portfolio for that Quarter which will be equal to the sum of:

(i) $YBPMW_y$ x $QBPH_Q$;

(ii) $MBPMW_{m1\text{-}for}$ x $MBPH_{m1}$;

(iii) $MBPMW_{m2\text{-}for}$ x $MBPH_{m2}$;

(iv) $MBPMW_{m3\text{-}for}$ x $MBPH_{m3}$;

(v) $YP(7x16)PMW_y$ x $QP(7x16)PH_Q$;

(vi) $MP(7x16)PMW_{m1\text{-}for}$ x $MP(7x16)PH_{m1}$;

(vii) $MP(7x16)PMW_{m2\text{-}for}$ x $MP(7x16)PH_{m2}$;

(viii) $MP(7x16)PMW_{m3\text{-}for}$ x $MP(7x16)PH_{m3}$;

(ix) $MSP(7x6)PMW_{m1\text{-}for}$ x $MSP(7x6)PH_{m1}$;

(x) $MSP(7x6)PMW_{m2\text{-}for}$ x $MSP(7x6)PH_{m2}$;

(xi) $MSP(7x6)PMW_{m3\text{-}for}$ x $MSP(7x6)PH_{m3}$;

(xii) $QBPMW_Q$ x $QBPH_Q$; and

(xiii) $QP(7x16)PMW_Q$ x $QP(7x16)PH_Q$;

where:

$YBPMW_y$ is the total capacity of One-Year Base Products, expressed in MWs, acquired for the Energy Product Portfolio for 2004 or 2005;

$QBPH_Q$ is the total number of hours in Base Periods that occur in that Quarter;

$MBPMW_{m1\text{-}for}$ is the total capacity of Monthly Base Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the first month of that Quarter;

$MBPH_{m1}$ is the total number of hours in Base Periods that occur in the first month of that Quarter;

$MBPMW_{m2\text{-}for}$ is the total capacity of Monthly Base Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the second month of that Quarter;

MBPH $_{m2}$ is the total number of hours in Base Periods that occur in the second month of that Quarter;

MBPMW$_{m3\text{-}for}$ is the total capacity of Monthly Base Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the third month of that Quarter;

MBPH $_{m3}$ is the total number of hours in Base Periods that occur in the third month of that Quarter;

YP(7x16)PMW$_{y}$ is the total capacity of One-Year Peak (7x16) Products, expressed in MWs, acquired for the Energy Product Portfolio for 2004/ 2005;

QP(7x16)PH$_{Q}$ is the total number of hours in Peak (7x16) Periods that occur in that Quarter;

MP(7x16)PMW$_{m1\text{-}for}$ is the total capacity of Monthly Peak (7x16) Products, expressed in MWs, forecast in the Monthly Product Schedule to that Quarter to be acquired for the Energy Product Portfolio for the first month of that Quarter;

MP(7x16)PH$_{m1}$ is the total number of hours in Peak (7x16) Periods that occur in the first month of that Quarter;

MP(7x16)PMW$_{m2\text{-}for}$ is the total capacity of Monthly Peak (7x16) Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the second month of that Quarter;

MP(7x16)PH$_{m2}$ is the total number of hours in Peak (7x16) Periods that occur in the second month of that Quarter;

MP(7x16)PMW$_{m3\text{-}for}$ is the total capacity of Monthly Peak (7x16) Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the third month of that Quarter;

MP(7x16)PH$_{m3}$ is the total number of hours in Peak (7x16) Periods that occur in the third month of that Quarter;

MSP(7x6)PMW$_{m1\text{-}for}$ is the total capacity of Monthly Super Peak (7x6) Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the first month of that Quarter;

MSP(7x6)PH$_{m1}$ is the total number of hours in Super Peak (7x6) Periods that occur in the first month of that Quarter;

MSP(7x6)PMW$_{m2\text{-}for}$ is the total capacity of Monthly Super Peak (7x6) Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio I for the second month of that Quarter;

MSP(7x6)PH$_{m2}$ is the total number of hours in Super Peak (7x6) Periods that occur in the second month of that Quarter;

MSP(7x6)PMW$_{m3\text{-}for}$ is the total capacity of Monthly Super Peak (7x6) Products, expressed in MWs, forecast in the Monthly Product Schedule for that Quarter to be acquired for the Energy Product Portfolio for the third month of that Quarter;

MSP(7x6)PH$_{m3}$ is the total number of hours in Super Peak (7x6) Periods that occur in the third month of that Quarter;

QBPMW$_Q$ is the total capacity of Quarterly Base Products, expressed in MWs, acquired for the Energy Product Portfolio for that Quarter;

QP(7x16)PMW$_Q$ is the total capacity of Quarterly Peak (7x16) Products, expressed in MWs, acquired for the Energy Product Portfolio for that Quarter;

Total RRT Transition Rate Target Volumes means (i) in relation to One-Year Products for a year, EESI's reasonable forecast of the total volume of One-Year Base Products and One-Year Peak Products required (with joint procurement) for the RRT Transition Rate Customersas set out in either Table 1 or Table 2 of Schedule "B" to the Non-RCC 2004/2005 Plan and (ii) in relation to Monthly Products, EESI's reasonable forecast of the volume of Monthly Base Products and Monthly Peak Products required (with joint procurement) for the RRT Transition Rate Customers for a month, as set out in the Monthly Product Schedule for the Quarter in which that month occurs.

Total RRT Transition Rate Volumes means (i) in relation to One-Year Products for a year, EESI's reasonable forecast of the total volume of One-Year Base Products and One-Year Peak Products required (with separate procurement) for the RRT Transition Rate Customers as set out in either Table 1 or Table 2 of Schedule "B" to the Non-RCC 2004/2005 Plan and (ii) in relation to Monthly Products, EESI's reasonable forecast of the volume of Monthly Base Products and Monthly Peak Products required (with separate procurement) for the RRT Transition Rate Customers for a month, as set out in the Monthly Product Schedule for the Quarter in which that month occurs.

Schedule B
to the Non-Rate Classification Customer 2004 and 2005 Energy Price Setting Plan
dated November 18, 2003

COMPOSITION OF TARGET ENERGY PORTFOLIO – ONE-YEAR PRODUCTS

The contents of this Schedule constitute Commercially Sensitive Information and therefore are excluded from any public filing with the AEUB.

Schedule C

to the Non-Rate Classification Customer 2004 and 2005 Energy Price Setting Plan
dated November 18, 2003

FORMS OF MONTHLY PRODUCT SCHEDULES

The contents of this Schedule constitute Commercially Sensitive Information and therefore are excluded from any public filing with the AEUB.

Schedule D

to the Non-Rate Classification Customer 2004 and 2005 Energy Price Setting Plan
dated November 18, 2003

PROTOCOL FOR PFO ROUND

The contents of this Schedule constitute Commercially Sensitive Information and therefore are excluded from any public filing with the AEUB.

Schedule E

to the Non-Rate Classification Customer 2004 and 2005 Energy Price Setting Plan dated November 18, 2003

CERTIFICATION OF COMPLIANCE – RFO ROUND

The contents of this Schedule constitute Commercially Sensitive Information and therefore are excluded from any public filing with the AEUB.

Schedule F
to the 2004 and 2005 Energy Price Setting Plan
dated November 18, 2003

CERTIFICATION OF COMPLIANCE – INTER-SESSION ROUND

The contents of this Schedule constitute Commercially Sensitive Information and therefore are excluded from any public filing with the AEUB.

Attachment "3"
to the EESI 2004 RRT Amended Application Letter for Non-Rate Classification Customers
dated November 18, 2003

ENERGY CHARGE SCHEDULE APPLICABLE FOR 2004/2005 – NON-RATE CLASSIFICATION CUSTOMERS

The Average Energy Charge (**AEC**) applicable to each EESI Regulated Rate Tariff Transition Rate – Non-Rate Classification Customer (Non-RCC) Classification - for each Quarter in 2004 and 2005 will be determined as follows:

AEC = [(Peak Energy Portfolio Price x NRCFPLP + Off Peak Energy Portfolio Price x (1 - NRCFPLP)) x CC x HC x LF + PTC] x (1 + RM)

where:

"Peak Energy Portfolio Price" is the Peak Energy Portfolio Price for that Quarter, expressed in $/MWh, determined in accordance with the Non-RCC 2004/2005 Energy Price Setting Plan (Non-RCC 2004/2005 Plan).

"NRCFPLP" is the EESI RRT Non-Rate Classification Customer Forecast Peak Load Portion, as defined in Schedule "A" to the 2004/2005 Energy Price Setting Plan, for that Rate Classification for that Quarter.

"Off Peak Energy Portfolio Price" is the Off Peak Energy Portfolio Price for that Quarter, expressed in $/MWh, determined in accordance with the Non-RCC 2004/2005 Plan.

"CC" is a factor of 1.0042 on account credit cost.

"LF" is the current Aggregate Line Loss Factor (including Unaccounted for Energy) which is applicable to the EESI's RRT Non-RC Customer Classification for which the AEC is being determined for 2004 and 2005.

EESI RRT Non-RCC Classification	Line Loss Factor
Small Commercial	1.0338
Lighting	1.0338

"HC" is a factor of 1.0015 on account of hedging cost.

"PTC" is a flow through of the Alberta Power Pool trading charge, currently set at $0.136/MWh.

"RM" is the Return Margin for that Quarter determined as follows:

(a) if the pre-RM Average Energy Rate is less than or equal to $75/MWh, then:

RM = .0249; or

(b) if the pre-RM Average Energy Rate is greater than $75/MWh, then:

RM = [.0249 x 75 + .005 x (pre-RM Average Energy Rate - 75)] / pre-RM Average Energy Rate

where:

pre-RM Average Energy Rate equals (Peak Energy Portfolio Price x NRCFPLP + Off Peak Energy Portfolio Price x (1 - NRCFPLP)) x CC x HC x LF + PTC

To the extent that all or a portion of the Super Peak (7x6) Product is acquired through the Power Pool, the return margin applied for the relevant Quarter would be adjusted in accordance with the following formula:

$ARM_q = (ARM_1 \text{ X } TEPV_1 \div TEPV_q) + (ARM_2 \text{ x } TEPV_2 \div TEPV_q) + (ARM_3 \text{ x } TEPV_3 \div TEPV_q)$

where

ARM_q is the Adjusted Return Margin for the purposes of the Energy Charge Schedule for a Quarter.

ARM_1 is the Adjusted Return Margin for the first month of the Quarter based on the following formula:

$ARM_1 = \{1 - [(PPV_1 \text{ x } PPVP_1 \text{ x } 0.75) \div (TEPP_1 \text{ x } TEPV_1)]\} \text{ x } 2.49\%$

where

PPV_1 is the Pool Price Volume which is based on the total energy acquired from the Power Pool on a flow through basis for the first month of the Quarter.

$PPVP_1$ is the Pool Price Volume Price which is based on the weighted average price of the volume purchased from the Power Pool for the first month of a Quarter.

$TEPP_1$ is the Total Energy Portfolio Price which means, for the first month of a Quarter, the average price (weighted by volume) of the Products in the Energy Product Portfolio for that period, including the Pool Price Volume, expressed in $/MWh.

$TEPV_1$ is the Total Energy Portfolio Volume which means, for the first month of a Quarter, the total volume of Products in the Energy Product Portfolio for that month including the Pool Price Volume.

ARM_2 is the Adjusted Return Margin for the second month of the Quarter and is calculated based on the same formula as ARM_1 *mutatis mutandis*.

ARM_3 is the Adjusted Return Margin for the third month of the Quarter and is calculated based on the same formula as ARM_1 *mutatis mutandis*.

$TEPV_q$ is the Total Energy Portfolio Volume which means, for the Quarter, the total volume of Products in the Energy Product Portfolio for that Quarter.

CONSULTATION AGREEMENT

BETWEEN:

EPCOR Energy Services Inc.
(hereinafter referred to as EESI)

- and -

Public Institutional Consumers of Alberta
(hereinafter referred to as the PICA)

WHEREAS:

(a) EESI intends to file with the Alberta Energy and Utilities Board (AEUB) for approval of a 2004 and 2005 Energy Price Setting Plan for Non-Rate Classification Customers (the Non-RCC 2004/2005 Plan), setting forth EESI's price setting method (Method) for energy supplies for Regulated Rate Tariff (RRT) Transition Rate Non-Rate Classification Customers (Non-RCC). Excluded from any copy of the Plan that may be filed with the AEUB will be any portions containing the Commercially Sensitive Information referred to in Section 2 of this Consultation Agreement.

(b) This Consultation Agreement sets out the agreement of the parties respecting ongoing consultations regarding the implementation of the Non-RCC 2004/2005 Plan and confidentiality of information.

IT IS HEREBY AGREED AS FOLLOWS:

1. Consultation

EESI and PICA (collectively, the Parties) will consult in good faith from time to time regarding the implementation of the Non-RCC 2004/2005 Plan. Among other things, this will require PICA to approve the load forecast volumes required for the operation of the Plan.

2. Confidentiality

(a) The Parties acknowledge and agree that the Method set forth in the Plan relies on commercially sensitive information, including specific pricing parameters, bidding strategies and details of the method for determining the energy supply products used for energy price setting for EESI's Non-RCC as set out in Schedules "B" through "F" to the Plan (Commercially Sensitive Information). The Parties further acknowledge and agree that the disclosure of that commercially sensitive information could adversely affect EESI's ability to acquire energy supplies for the Non-RCC and/or the costs incurred by EESI to acquire those supplies.

(b) The Parties agree to keep the Commercially Sensitive Information as well as any other similar information that they may receive in any consultations that they may have regarding the Non-RCC 2004/2005 Plan as contemplated in Section 1 of this Consultation Agreement, strictly confidential and to not use that Commercially Sensitive Information except for the purposes of the Non-RCC 2004/2005 Plan.

3. Payment of Costs

(a) EPCOR will pay the costs reasonably incurred by the PICA in relation to this Consultation Agreement and in implementing the Non-RCC 2004/2005 Plan on receipt from PICA of: (i) an invoice(s) from PICA for such costs; and (ii) written confirmation from PICA that the costs included in the invoice(s) have been reasonably incurred and the cost claim has been prepared in accordance with the AEUB's guidelines for costs claims.

(b) EESI will include in the energy costs for the Non-RCC the amounts paid by EESI to PICA under this Consultation Agreement.

4. Without Prejudice

The Parties agree that the fact that PICA has entered this Consultation Agreement shall be without prejudice to any position that PICA may wish to take before the AEUB concerning the application that was filed by EESI on November 17, 2003 for approval of the Non-RCC 2004/2005 Plan and for approval of other amendments to the EESI 2004 Regulated Rate Tariff Application, including, but not necessarily limited to, issues, if any concerning the requested return margin, cost of credit factor, use of a separate energy procurement pool for calculation of the NRCC energy rate and line losses for Non-RC Customers.

5. General Terms and Conditions

(a) The division of this Consultation Agreement into headings and paragraphs is for convenience and reference only and is not to affect the interpretation or construction of this Consultation Agreement.

(b) This Consultation Agreement constitutes the entire agreement between the Parties and no other agreements, expressed or implied, have been made.

(c) This Consultation Agreement will be binding upon, and enure to the benefit of, the Parties and each of their respective trustees, administrators, successors and permitted assigns.

(d) This Consultation Agreement may be executed in any number of counterparts.

DATED as of the 24th day of November, 2003

EPCOR Energy Services Inc.

Per:_____

Public Institutional Consumers of Alberta

Per:_____

APPENDIX 5 – NON-RATE CLASSIFICATION CUSTOMER BILL COMPARISONS

"Commercial &
Lighting Bill Compari

(Consists of 5 pages)

EESI

Changes From Final 2002 Bills @ October 1 to Final 2003 Bills @ October 1

		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
Line No.	Rate Class Description	Final 2002 @ October 1 ¢/kWh	Energy Cost Change ¢/kWh	D&T Cost Change ¢/kWh	Franchise Fee Cost Change ¢/kWh	Final 2003 @ January 1 ¢/kWh	Energy Cost Change ¢/kWh	2001 RROT Shortfall Rider Cost Change ¢/kWh	Final 2003 @ April 1 ¢/kWh	Energy Cost Change ¢/kWh	D&T Cost Change ¢/kWh	Final 2003 @ July 1 ¢/kWh	Energy Cost Change ¢/kWh	D&T Cost Change ¢/kWh	Cessation of 2000 Deferral Rider ¢/kWh	Final 2003 @ October 1 ¢/kWh	Change (O - A) ¢/kWh	Change P / A %
1	Security Light Service	12.21	(0.85)	6.68	(0.00)	18.03	(0.00)	0.03	18.06	(0.13)	0.25	18.18	1.31	(0.75)	(0.81)	17.93	5.72	46.9%
2	Small Commercial Service	11.58	0.33	0.12	0.00	12.03	0.00	0.22	12.25	0.02	0.18	12.45	0.11	(0.75)	(0.81)	11.00	(0.58)	(5.0%)

Note: - Final 2002 Bills are for the 2002 calendar year.
- Final 2003 Bills are for the 2003 calendar year.
- Monthly consumption was assumed to be constant.

EESI

Changes From Final 2003 Bills @ October 1 to Final 2004 Bills @ January 1

Line No.	Rate Class Description	A Final 2003 @ October 1 ¢/kWh	B D&T Cost Change ¢/kWh	C Final 2003 @ December 1 ¢/kWh	D Energy Cost Change ¢/kWh	E D&T Cost Change ¢/kWh	F Franchise Fee Cost Change ¢/kWh	G Cessation of 2001 RROT Shortfall Rider ¢/kWh	H Final 2004 @ January 1 ¢/kWh	I Change (H - A) ¢/kWh	J Change I / A %
1	Security Light Service	17.93	0.16	18.09	(0.99)	0.26	0.01	0.67	18.04	0.12	0.6%
2	Small Commercial Service	11.00	(0.01)	10.99	(0.56)	0.44	0.01	(2.18)	8.69	(2.31)	(21.0%)

Note: - Final 2003 Bills are for the 2003 calendar year.
- Final 2004 Bills are for the 2004 calendar year.
- Monthly consumption was assumed to be constant.

EESI

Changes From Final 2004 Bills @ January 1 to Final 2005 Bills @ January 1

Line No.	Rate Class Description	A **Final 2004 @ January 1 ¢/kWh**	B Energy Cost Change ¢/kWh	D **Final 2005 @ January 1 ¢/kWh**	E **Change (D - A) ¢/kWh**	F **Change E / A %**
1	Security Light Service	**18.04**	(0.36)	**17.68**	**(0.36)**	**(2.0%)**
2	Small Commercial Service	**8.69**	(0.43)	**8.26**	**(0.43)**	**(5.0%)**

Note: - Final 2004 Bills are for the 2004 calendar year.
- Final 2005 Bills are for the 2005 calendar year.
- Monthly consumption was assumed to be constant.

EPCOR Energy Services Inc. (EESI)
Effects of Rate and Rider Changes for Security Light Service, 2002 - 2005

Energy Price Assumptions		Unit	Customer Usage Level		
			Low Usage	Typical Usage	High Usage
2005 RRT Energy Price	3.66¢/kWh				
2004 RRT Energy Price	4.02¢/kWh				
2003 RROT Energy Price @ Oct 1, 2003	5.01¢/kWh				
2003 RROT Energy Price @ Jul 1, 2003	3.70¢/kWh				
2003 RROT Energy Price @ Apr 1, 2003	3.83¢/kWh	Deemed kWh	38	73	175
2003 RROT Energy Price @ Jan 1, 2003	3.83¢/kWh	Watts	70	150	400
2002 RROT Energy Price @ Oct 1, 2002	4.69¢/kWh				

Row No.	Rate Component	Relative to Row	Effective Date	Costs for Each Usage Level ($/month) and Percentage Change Relative to Specified Row					
1	October Base 2002 Rate (excludes Rate Riders and Franchise Fee)	-	Oct 1, 02	**$8.34**	-	**$8.56**	-	**$14.94**	-
1a	2000 Deferral Rider	[1]	Jan 1, 02	$0.29	4.6%	$0.59	6.9%	$1.46	9.7%
1b	2001 RROT Shortfall Rider	[1]	Jan 1, 02	($0.25)	(3.9%)	($0.51)	(6.0%)	($1.25)	(8.4%)
1c	Franchise Fee	[1]	Jan 1, 02	$0.13	2.1%	$0.27	3.2%	$0.66	4.4%
2	**Final 2002 Bills, Oct - Dec 2002**	[1]	Oct 1, 02	**$8.51**	**2.7%**	**$8.91**	**4.1%**	**$15.80**	**5.8%**
2a	Changes between Final 2002 Bills & 2003 Base Rate								
2b	Energy Cost Change	[2]	Jan 1, 03	($0.31)	(4.7%)	($0.62)	(7.0%)	($1.53)	(9.7%)
3	**Base 2003 Rate**	[2]	Jan 1, 03	**$8.20**	**(4.7%)**	**$8.29**	**(7.0%)**	**$14.27**	**(9.7%)**
3a	Changes between 2002 DT Rates @ Oct 1 & 2003 DT Rates @ Jan 1								
3b	Distribution and Transmission Cost Change	[3]	Jan 1, 03	$2.44	39.3%	$4.88	58.9%	$11.65	83.3%
3c	Changes between 2002 Franchise Fee Rate @ Oct 1 & 2003 Franchise Fee Rate @ Jan 1								
3d	Franchise Fee Cost Change	[3]	Jan 1, 03	($0.00)	(0.1%)	($0.00)	(0.0%)	$0.01	0.1%
4	**Final 2003 Bills**	[3]	Jan 1, 03	**$8.64**	**39.7%**	**$13.17**	**58.9%**	**$26.13**	**83.9%**
4a	Changes between 2003 Base Rate @ Jan 1 & 2003 Base Rate @ Apr 1								
4b	Energy Cost Change	[4]	Apr 1, 03	($0.00)	(0.0%)	($0.00)	(0.0%)	($0.01)	(0.0%)
5	**Base 2003 Rate**	[4]	Apr 1, 03	**$8.64**	**(0.0%)**	**$13.16**	**(0.0%)**	**$26.12**	**(0.0%)**
5a	Changes between 2001 RROT Shortfall Rider @ Jan 1 & 2001 RROT Shortfall Rider @ Apr 1								
5b	2001 RROT Shortfall Rider Cost Change	[5]	Apr 1, 03	$0.01	0.1%	$0.02	0.2%	$0.05	0.2%
6	**Final 2003 Bills**	[5]	Apr 1, 03	**$8.65**	**0.1%**	**$13.18**	**0.2%**	**$26.17**	**0.2%**
6a	Changes between 2003 Base Rate @ Apr 1 & 2003 Base Rate @ Jul 1								
6b	Energy Cost Change	[6]	Jul 1, 03	($0.05)	(0.5%)	($0.09)	(0.7%)	($0.20)	(0.8%)
7	**Base 2003 Rate**	[6]	Jul 1, 03	**$8.60**	**(0.5%)**	**$13.09**	**(0.7%)**	**$25.95**	**(0.9%)**
7a	Changes between 2003 DT Rates @ Apr 1 & 2003 DT Rates @ Jul 1								
7b	Distribution and Transmission Cost Change	[7]	Jul 1, 03	$0.09	1.2%	$0.18	1.4%	$0.47	1.8%
8	**Final 2003 Bills**	[7]	Jul 1, 03	**$8.69**	**1.0%**	**$13.27**	**1.4%**	**$26.42**	**1.8%**
8a	Changes between 2003 Base Rate @ Jul 1 & 2003 Base Rate @ Oct 1								
8b	Energy Cost Change	[8]	Oct 1, 03	$0.47	5.5%	$0.96	7.3%	$2.34	9.0%
9	**Base 2003 Rate**	[8]	Oct 1, 03	**$9.16**	**5.6%**	**$14.23**	**7.2%**	**$28.76**	**8.9%**
9a	Changes between 2003 DT Rates @ Jul 1 & 2003 DT Rates @ Oct 1								
9b	Distribution and Transmission Cost Change	[9]	Oct 1, 03	($0.27)	(2.9%)	($0.55)	(3.9%)	($1.38)	(4.7%)
9c	Cessation of 2000 Deferral Rider	[1]	Oct 24, 03	($0.29)	(3.2%)	($0.59)	(4.1%)	$1.46	5.2%
10	**Final 2003 Bills**	[9]	Oct 1, 03	**$8.60**	**(6.1%)**	**$13.09**	**(8.0%)**	**$25.98**	**(9.8%)**
10a	Changes between 2003 DT Rates @ Oct 1 & 2003 DT Rates @ Dec 1								
10b	Distribution and Transmission Cost Change	[10]	Dec 1, 03	$0.06	0.7%	$0.12	0.9%	$0.30	1.2%
11	**Final 2003 Bills**	[10]	Dec 1, 03	**$8.66**	**0.7%**	**$13.21**	**0.9%**	**$26.28**	**1.2%**
11a	Changes between 2003 Base Rate @ Oct 1 & 2004 Base Rate @ Jan 1								
11b	Energy Cost Change	[11]	Jan 1, 04	($0.36)	(4.1%)	($0.73)	(5.5%)	($1.78)	(6.8%)
12	**Predicted Base 2004 Rate**	[11]	Jan 1, 04	**$8.31**	**(4.1%)**	**$12.48**	**(5.5%)**	**$24.47**	**(6.8%)**
12a	Changes between 2003 DT Rates @ Dec 1 & 2004 DT Rates @ Jan 1								
12b	Distribution and Transmission Cost Change	[12]	Jan 1, 04	$0.07	0.8%	$0.13	1.0%	$0.51	2.1%
12c	Changes between 2003 Franchise Fee Rate @ Dec 1 & 2004 Franchise Fee Rate @ Jan 1								
12d	Franchise Fee Cost Change	[12]	Jan 1, 04	$0.01	0.1%	$0.01	0.1%	$0.01	0.0%
12e	Cessation of 2001 RROT Shortfall Rider	[1]	Jan 1, 04	$0.25	3.0%	$0.51	4.1%	$1.25	5.1%
12f	Cessation of Change in 2001 RROT Shortfall Rider (to 2003 Base Rate @ Apr 1)	[5]	Jan 1, 04	($0.01)	(0.1%)	($0.02)	(0.2%)	($0.05)	(0.2%)
13	**Predicted 2004 Bills**	[12]	Jan 1, 04	**$8.63**	**3.9%**	**$13.17**	**5.9%**	**$26.19**	**7.0%**
13a	Changes between 2004 Base Rate @ Jan 1 & 2005 Base Rate @ Jan 1								
13b	Energy Cost Change	[13]	Jan 1, 05	($0.13)	(1.5%)	($0.25)	(2.0%)	($0.65)	(2.5%)
14	**Predicted Base 2005 Rate**	[13]	Jan 1, 05	**$8.50**	**(1.5%)**	**$12.91**	**(2.0%)**	**$25.54**	**(2.5%)**

Note: Monthly consumption was assumed to be constant.

EPCOR Energy Services Inc. (EESI)
Effects of Rate and Rider Changes for Small Commercial Service, 2002 - 2005

Energy Price Assumptions		Unit	Customer Usage Level		
			Low Usage	Typical Usage	High Usage
2005 RRT Energy Price	4.97¢/kWh				
2004 RRT Energy Price	5.41¢/kWh				
2003 RROT Energy Price @ Oct 1, 2003	5.96¢/kWh				
2003 RROT Energy Price @ Jul 1, 2003	5.85¢/kWh	kWh	1,095	2,190	10,950
2003 RROT Energy Price @ Apr 1, 2003	5.83¢/kWh	kW	5	10	50
2003 RROT Energy Price @ Jan 1, 2003	5.83¢/kWh	%	30.0%	30.0%	30.0%
2002 RROT Energy Price @ Oct 1, 2002	5.50¢/kWh				

Row No.	Rate Component	Relative to Row	Effective Date	Costs for Each Usage Level ($/month) and Percentage Change Relative to Specified Row					
1	October Base 2002 Rate (excludes Rate Riders and Franchise Fee)	-	Oct 1, 02	**97.38**	-	**$184.47**	-	**$881.24**	-
1a	2000 Deferral Rider	[1]	Jan 1, 02	$8.89	9.1%	$17.79	9.6%	$89.95	10.1%
1b	2001 RROT Shortfall Rider	[1]	Jan 1, 02	$21.57	22.2%	$43.14	23.4%	$215.72	24.5%
1c	Franchise Fee	[1]	Jan 1, 02	$4.06	4.2%	$8.12	4.4%	$40.62	4.6%
2	**Final 2002 Bills, Oct - Dec 2002**	[1]	Oct 1, 02	**$131.90**	**35.4%**	**$253.52**	**37.4%**	**$1,226.53**	**39.2%**
2a	Changes between Final 2002 Bills & 2003 Base Rate								
2b	Energy Cost Change	[2]	Jan 1, 03	$3.61	2.7%	$7.23	2.9%	$36.14	2.9%
3	**Base 2003 Rate**	[2]	Jan 1, 03	**$135.51**	**2.7%**	**$260.75**	**2.9%**	**$1,262.67**	**2.9%**
3a	Changes between 2002 DT Rates @ Oct 1 & 2003 DT Rates @ Jan 1								
3b	Distribution and Transmission Cost Change	[3]	Jan 1, 03	$1.38	1.0%	$2.66	1.0%	$12.81	1.0%
3c	Changes between 2002 Franchise Fee Rate @ Oct 1 & 2003 Franchise Fee Rate @ Jan 1								
3d	Franchise Fee Cost Change	[3]	Jan 1, 03	$0.04	0.0%	$0.07	0.0%	$0.33	0.0%
4	**Final 2003 Bills**	[3]	Jan 1, 03	**$136.94**	**1.0%**	**$263.46**	**1.0%**	**$1,275.80**	**1.0%**
4a	Changes between 2003 Base Rate @ Jan 1 & 2003 Base Rate @ Apr 1								
4b	Energy Cost Change	[4]	Apr 1, 03	-	-	-	-	-	-
5	**Base 2003 Rate**	[4]	Apr 1, 03	**$136.94**	-	**$263.46**	-	**$1,275.80**	-
5a	Changes between 2001 RROT Shortfall Rider @ Jan 1 & 2001 RROT Shortfall Rider @ Apr 1								
5b	2001 RROT Shortfall Rider Cost Change	[5]	Apr 1, 03	$2.36	1.7%	$4.71	1.8%	$23.54	1.8%
6	**Final 2003 Bills**	[5]	Apr 1, 03	**$139.30**	**1.7%**	**$268.17**	**1.8%**	**$1,299.34**	**1.8%**
6a	Changes between 2003 Base Rate @ Apr 1 & 2003 Base Rate @ Jul 1								
6b	Energy Cost Change	[6]	Jul 1, 03	$0.26	0.2%	$0.53	0.2%	$2.63	0.2%
7	**Base 2003 Rate**	[6]	Jul 1, 03	**$139.56**	**0.2%**	**$268.70**	**0.2%**	**$1,301.97**	**0.2%**
7a	Changes between 2003 DT Rates @ Apr 1 & 2003 DT Rates @ Jul 1								
7b	Distribution and Transmission Cost Change	[7]	Jul 1, 03	$1.99	1.4%	$3.99	1.5%	$19.94	1.5%
8	**Final 2003 Bills**	[7]	Jul 1, 03	**$141.55**	**1.4%**	**$272.69**	**1.5%**	**$1,321.91**	**1.5%**
8a	Changes between 2003 Base Rate @ Jul 1 & 2003 Base Rate @ Oct 1								
8b	Energy Cost Change	[8]	Oct 1, 03	$1.25	0.9%	$2.50	0.9%	$12.48	0.9%
9	**Base 2003 Rate**	[8]	Oct 1, 03	**$142.80**	**0.9%**	**$275.18**	**0.9%**	**$1,334.39**	**0.9%**
9a	Changes between 2003 DT Rates @ Jul 1 & 2003 DT Rates @ Oct 1								
9b	Distribution and Transmission Cost Change	[9]	Oct 1, 03	($8.25)	(5.8%)	($16.49)	(6.0%)	($82.46)	(6.2%)
9c	Cessation of 2000 Deferral Rider	[1]	Oct 24, 03	($8.89)	(6.2%)	($17.79)	(6.5%)	($89.95)	(6.7%)
10	**Final 2003 Bills**	[9]	Oct 1, 03	**$125.66**	**(12.0%)**	**$240.90**	**(12.5%)**	**$1,162.98**	**(12.8%)**
10a	Changes between 2003 DT Rates @ Oct 1 & 2003 DT Rates @ Dec 1								
10b	Distribution and Transmission Cost Change	[10]	Dec 1, 03	($0.10)	(0.1%)	($0.22)	(0.1%)	($1.10)	(0.1%)
11	**Final 2003 Bills**	[10]	Dec 1, 03	**$125.56**	**(0.1%)**	**$240.68**	**(0.1%)**	**$1,161.88**	**(0.1%)**
11a	Changes between 2003 Base Rate @ Oct 1 & 2004 Base Rate @ Jan 1								
11b	Energy Cost Change	[11]	Jan 1, 04	($6.11)	(4.9%)	($12.21)	(5.1%)	($61.07)	(5.3%)
12	**Predicted Base 2004 Rate**	[11]	Jan 1, 04	**$119.45**	**(4.9%)**	**$228.47**	**(5.2%)**	**$1,100.81**	**(5.3%)**
12a	Changes between 2003 DT Rates @ Dec 1 & 2004 DT Rates @ Jan 1								
12b	Distribution and Transmission Cost Change	[12]	Jan 1, 04	$4.77	4.0%	$9.61	4.2%	$48.34	4.4%
12c	Changes between 2003 Franchise Fee Rate @ Dec 1 & 2004 Franchise Fee Rate @ Jan 1								
12d	Franchise Fee Cost Change	[12]	Jan 1, 04	$0.06	0.1%	$0.13	0.1%	$0.66	0.1%
12e	Cessation of 2001 RROT Shortfall Rider	[1]	Jan 1, 04	($21.57)	(18.1%)	($43.14)	(18.9%)	($215.72)	(19.6%)
12f	Cessation of Change in 2001 RROT Shortfall Rider (to 2003 Base Rate @ Apr 1)	[5]	Jan 1, 04	($2.36)	(2.0%)	($4.71)	(2.1%)	($23.54)	(2.1%)
13	**Predicted 2004 Bills**	[12]	Jan 1, 04	**$100.35**	**(16.0%)**	**$190.36**	**(16.7%)**	**$910.55**	**(17.3%)**
13a	Changes between 2004 Base Rate @ Jan 1 & 2005 Base Rate @ Jan 1								
13b	Energy Cost Change	[13]	Jan 1, 05	($4.76)	(4.7%)	($9.51)	(5.0%)	($47.55)	(5.2%)
14	**Predicted Base 2005 Rate**	[13]	Jan 1, 05	**$95.59**	**(4.7%)**	**$180.85**	**(5.0%)**	**$863.00**	**(5.2%)**

Note: Monthly consumption was assumed to be constant.

SCHEDULE A – EESI RRT PRICE SCHEDULES

"RRT Price Schedule.doc"

(Consists of 11 pages)

Schedule "A"

Regulated Rate Tariff – Price Schedules

Applicable to RRT Customers in the EPCOR Distribution Inc. Service Area Effective January 1, 2004

EPCOR Energy Services Inc.

Revised December 4, 2003

Regulated Rate Tariff - Price Schedule

Residential Service

Applicable: To Residential Rate Classification Customers within the City of Edmonton that have not chosen a Retailer. Residential Service is only available to single or two family dwellings consisting of a suite of rooms provided with sleeping and cooking facilities which is being used primarily for domestic use and which have an energy meter. Where a business is conducted from a dwelling that is also used for domestic purposes, Residential Service is not available if the service panel capacity is larger than 200 amps.

Price:

Energy Charge:

Shall be

$ · per kWh for the period January 1, 2004 to March 31, 2004

System Access Service Charge:

Shall be $0.00752 per kWh

Distribution Access Service Charge:

Shall be $9.00 per month plus $0.00607 per kWh

Administration charge: $4.06 / month

Franchise Fee Charge:

Shall be the amount EESI is billed by EPCOR Distribution Inc., for the site, for the applicable billing period.

Regulations:

Service under all EPCOR Energy Services Inc.'s Rates, Charges and Riders are subject to the Terms and Conditions of Regulated Rate Service as approved by the Alberta Energy and Utilities Board.

Regulated Rate Tariff - Price Schedule

Security Light Service

Applicable: To existing unmetered Security Light Service customers within the City of Edmonton that have not chosen an alternative price option or an alternative retail supplier of electricity. This price is not available to new services.

Consumption: The deemed energy consumption per month varies with nominal wattage as follows:

	70 W	100 W	150 W	250 W	400 W
Monthly kWh	36	50	73	114	179

Price:

Energy Charge:

Shall be

$ • per kWh for the period January 1, 2004 to March 31, 2004

System Access Service Charge:

Shall be $0.00735 per kWh

Distribution Access Service Charge:

Shall be $2.87 per month plus $0.07153 per kWh

Administration charge: $ 1.33 / month

Franchise Fee Charge:

Shall be the amount EESI is billed by EPCOR Distribution Inc., for the site, for the applicable billing period.

Regulations:

Service under all EPCOR Energy Services Inc.'s Rates, Charges and Riders are subject to the Terms and Conditions of Regulated Rate Service as approved by the Alberta Energy and Utilities Board.

Regulated Rate Tariff - Price Schedule

Commercial Service < 50 kVA

Applicable: To each separate electrical service, within the City of Edmonton, which is not eligible for Residential or Security Light Service and which has a billing demand of less than 50 kVA, and for which,

(i) Total annual consumption of electric energy is less than 250 MWh, and;

(ii) the customer has not chosen a Retailer.

Price:

Energy Charge:

Shall be

$ • per kWh for the period January 1, 2004 to March 31, 2004

System Access Service Charge:

Shall be $0.00644 per kWh

Distribution Access Service Charge:

Shall be $5.26 per month plus $0.01792 per kWh

Administration charge: $ 5.07 / month

Billing Demand is the greatest of:

i) The registered kVA of demand at the highest 15 minute interval recorded at each site, by the current or a previous customer, in the 12 month period ending with the current billing period,

ii) The Minimum Demand as determined by any applicable contract.

Franchise Fee Charge:

Shall be the amount EESI is billed by EPCOR Distribution Inc., for the site, for the applicable billing period.

Regulations:

Service under all EPCOR Energy Services Inc.'s Rates, Charges and Riders are subject to the Terms and Conditions of Regulated Rate Service as approved by the Alberta Energy and Utilities Board.

Regulated Rate Tariff - Price Schedule

Commercial Service > 50 kVA

Applicable: To each separate electrical service, within the City of Edmonton, with a billing demand greater than or equal to 50 kVA, and for which,

(i) Total annual consumption of electric energy is less than 250 MWh, and;
(ii) The customer has not chosen a Retailer.

Price:

Energy Charge:

Shall be

$ · per kWh for the period January 1, 2004 to March 31, 2004

System Access Service Charge:

Shall be $0.00644 per kWh

Distribution Access Service Charge:

Shall be $42.77 per month plus $1.29 per kVA of billing demand plus $0.00630 per kWh

Administration charge: $5.07 / month

Billing Demand is the greatest of:

i) The registered kVA of demand at the highest 15 minute interval recorded at each site, by the current or a previous customer, in the 12 month period ending with the current billing period,
ii) The Minimum Demand as determined by any applicable contract,
iii) The Price Minimum of 50 kVA.

Franchise Fee Charge:

Shall be the amount EESI is billed by EPCOR Distribution Inc., for the site, for the applicable billing period.

Regulations:

Service under all EPCOR Energy Services Inc.'s Rates, Charges and Riders are subject to the Terms and Conditions of Regulated Rate Service as approved by the Alberta Energy and Utilities Board.

Regulated Rate Tariff – Price Schedule

Unmetered Option

Applicable: To each service where energy consumption is small and can be easily predicted. The estimated consumption will be based on equipment nameplate rating and operational patterns. These services will be supplied under the Price Schedule, Commercial Service < 50 kVA. EPCOR Energy

Services Inc. reserves the right to audit and re-estimate energy consumption. The customer may provide an acceptable meter socket and request metered service.

Deemed energy consumption for common unmetered services:

Device	Estimated Monthly Consumption kWh
Cable Television Signal Booster	300
Phone Booth 1 Lamp	75
Phone Booth 2 Lamp	150
Phone Booth 1 Lamp, 1 Sign	160
Phone Booth 2 Lamp, 1 Sign	265
Bus Shelter illuminated advertising	205
Airport "Caulder high line lights"	730
Airport Perimeter lights	3860
City – China Gate	1180
Drainage Flow Monitor (per location)	150
Rail Road Hazard Lights	82
Canadian Forces Base Lighting	19770

EPCOR Regulated Rate Tariff

Miscellaneous Fees

1. ACCOUNT CONNECTION FEE

A Connection fee is applied as follows:

a) Where power at a service is currently on at the time of application and where responsibility for paying the account is being transferred from an existing customer to a new customer at a site, the charge is $10.00. Three business days notice is required prior to the service being transferred to the responsibility of the new Customer. Expedited service is available at an additional charge of $10.00

b) Where an arrangement has been made and the account is being automatically transferred to the responsibility of a property owner or landlord upon a tenant applying for termination of power service, the charge is $10.00

c) Where a service exists but has been physically turned off at the time of application, the charge is $22.00. Three business days notice is required. Expedited service is available at an additional charge of $24.00

2. RECONNECTION OF SERVICE

The fee for reconnection of service after cut-off for non-payment of account shall be as $41.00.

3. RETURNED CHEQUE CHARGE

Where a customer's payment is not honoured by the customer's bank, a charge of $20 will apply for each such payment received by EPCOR Energy Services.

4. COLLECTION FEE

Where EPCOR delivers a "Turn-Off Notice" to a customer due to non-payment of amounts owing, a collection fee of $15.00 will be applied to the customer's account.

5. METER TESTING CHARGE

EPCOR Energy Services will arrange to test the accuracy of a customer's meter upon payment of a charge of $50.00 as a deposit. The customer can also be charged the actual cost of the meter check if the result of the meter check indicated the meter is functioning within the parameters defined by the Electricity and Gas Inspection Act. If the meter is proven to be defective, the customer's meter reading will be adjusted and no cost to the customer. The $50.00 deposit will be refunded.

6. COST RECOVERY CHARGES

For miscellaneous service requests including providing historical data and other record searches, the charge will be based on the estimated cost of providing the service.

SCHEDULE B – EESI RRT TERMS AND CONDITIONS

"EESI RRT Terms an Conditions.doc"

(Consists of 17 pages)

Attachment "1"
to the EESI 2004 RRT Amended Application Letter for Non-Rate Classification Customers
dated November 18, 2003

Regulated Rate Tariff – Terms and Conditions

EPCOR Energy Services Inc.

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ARTICLE 1 - GENERAL

1.1 Provision of Regulated Rate Service

EPCOR Distribution has made arrangements with EESI to perform EPCOR Distribution's obligations to provide Regulated Rate Service to Eligible Customers in its service area. EESI provides Regulated Rate Service under its Regulated Rate Tariffs that have been approved by the Board and includes these RRT Terms and the Price Schedule. The Price Schedule sets out the prices approved by the Regulator for Regulated Rate Service provided by EESI.

These RRT Terms are the terms and conditions upon which EESI offers and provides Regulated Rate Service to Eligible Customers.

The Regulated Rate Tariff is available for public inspection during normal business hours at EESI's business offices.

1.2 Effective Date

These RRT Terms will take effect on January 1, 2004.

1.3 Customers Bound by Regulated Rate Tariff

The Regulated Rate Tariff applies to each Customer. Without limiting the generality of the foregoing, the entering into of a Regulated Rate Service Agreement by a Customer, the receipt by the Customer of Regulated Rate Service or the payment by the Customer of a bill rendered by EESI in relation to Regulated Rate Service shall constitute acceptance by the Customer of all of the provisions of the Regulated Rate Tariff. Each Customer is also bound by EPCOR Distribution's Distribution Tariff.

1.4 Modification of Regulated Rate Tariff

No agent, employee or other representative of EESI is authorized to modify any provision or price contained in the Regulated Rate Tariff or to bind EESI to perform in any manner inconsistent with the Regulated Rate Tariff. Without limiting the generality of the foregoing, no agreement can provide for the waiver or alteration of any part of the Regulated Rate Tariff unless such agreement is first filed with and approved by the Regulator.

1.5 Regulatory Approval and Amendment

The Board has approved the RRT Terms. EESI may amend the RRT Terms by filing a notice of amendment with the Board. The amendment will take effect 60 days after such notice is filed unless the Board directs otherwise. Whenever the Board approves an amendment to the RRT Terms or an amendment otherwise takes effect, the applicable section(s) of the RRT Terms will be revised to incorporate the amendments and the effective date of the amendments will be indicated in the revised section(s).

ARTICLE 2 - DEFINITIONS AND INTERPRETATION

2.1 Definitions

The following words and phrases, whenever used in the Regulated Rate Tariff, shall have the following meanings:

"Alberta Interconnected Electric System" means the "interconnected electric system" as defined in the EUA.

"Board" means the Alberta Energy and Utilities Board established under the *Alberta Energy and Utilities Board Act, 2000, A-17.*

"Customer" means:

(a) An Eligible Customer who has not selected a Retailer; or

(b) an Eligible Customer, other than an Eligible Customer referred to in paragraph (a) of this definition, who is receiving Regulated Rate Service or who has applied for Regulated Rate Service from EESI.

"Business Day" means a day, which is not a Saturday, Sunday or statutory holiday in the Province of Alberta, and "day" means any calendar day.

"Customer of Record" means the Customer for whom EESI has opened an account pursuant to Section 3.2 or Section 5.9.

"Distribution Access Service" means "distribution access service" as defined in the EUA provided to Customers by means of EPCOR Distribution's Distribution System.

"Distribution System" means "electric distribution system" as defined in the EUA.

"Distribution Tariff" means, at any point in time, EPCOR Distribution's tariff for the provision of Distribution Access Service approved by the Board and in effect at such time.

"Electricity Services" means "electricity services" as defined in the EUA.

"Eligible Customer" means:

(a) a Rate Classification Customer, and

(b) any other customer, if the Owner's reasonable forecast of the customer's annual consumption of electric energy at a site is less than 250 megawatt hours of electric energy at that site.

"Energy" means "electric energy" as defined in the EUA, expressed in kilowatt hours.

"EPCOR Distribution" means EPCOR Distribution Inc. or any other person who acts as a Wire Services Provider with respect to EPCOR Distribution's Distribution System.

"EESI" means EPCOR Energy Services Inc.

"EUA" means the *Electric Utilities Act*, 2003, E-5.1, including the regulations enacted thereunder, as re-enacted, amended or replaced from time to time.

"Exchange" means "exchange" as defined in the EUA.

"Facilities" means physical plant (including, without limitation, transmission and distribution lines, transformers, meters, equipment and machinery).

"Force Majeure" means circumstances not reasonably within the control of EESI including acts of God, strikes, lockouts or other industrial disturbances, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, high water, washouts, inclement weather, orders or acts of civil or military authorities, civil disturbances, explosions, breakdown or accident to equipment, mechanical breakdowns, interruption of supply, goods or services including electricity or the electricity Distribution Service, the intervention of federal, provincial, or local government or from any of their agencies or boards, the order of direction of any court, and any other cause, whether of the kind herein enumerated or otherwise.

"Load" means Energy consumed by Customers together with allocated losses and other unaccounted for Energy.

"Non-Regulated Rate Services" means the various services, other than Regulated Rate Service, provided to a Customer by EESI and other Persons from time to time.

"Person" means a person, firm, partnership, corporation, organization or other association, and includes an individual member thereof.

"Point of Service" means the point at which EPCOR Distribution's service conductors are connected to the wires or apparatus of a Customer.

"Price Schedule" means EESI's Regulated Rate Tariff Price Schedules, approved by the Board.

"Rate Classification Customer" means a Residential Rate Classification Customer as defined in EESI's RRT Price Schedule.

"RRR Regulation" means the *Roles, Relationships and Responsibilities Regulation*, AR 169/2003.

"RRT Terms" means these terms and conditions, as they may be amended from time to time.

"RDS Regulation" means the *Regulated Default Supply Regulation*, AR 168/2003.

"Regulated Rate Service" means:

(a) arranging for the Exchange or purchase of Energy on behalf of a Customer;

(b) arranging for Distribution Access Service on behalf of a Customer in accordance with EESI's Regulated Rate Tariff.

"Regulated Rate Service Agreement" means an agreement between EESI and a Customer in a form acceptable to EESI.

"Regulated Rate Tariff" means EESI's Regulated Rate Tariff approved by the Board for Eligible Customers, including these RRT Terms, the Price Schedule, and RRT System Delivery and Billing Agreement.

"Regulator" means the Board.

"Residential Rate Classification Customer" means a customer receiving or eligible to receive Residential Service as specified in the Price Schedule.

"Retailer" means a "retailer" as defined in the EUA.

"RRT Arrangement Agreement" means the Agreement between EPCOR Distribution and EESI for EESI to provide a RRT service to Eligible Customers in the EPCOR Distribution service area.

"Service Connection" means all Facilities required for providing services up to the Point of Service.

"Site" means, in relation to a Service Connection for a Customer, the Point of Service for the Customer.

"Small Commercial Customer" means an Eligible Customer, other than a Residential Rate Classification Customer.

"System Controller" means the person referred to in section 7 of the EUA.

"Transmission Administrator" has the meaning given to it in the EUA.

"Wire Services Provider" means a "wires service provider" as defined in the EUA.

2.2 Conflicts

If there is any conflict between a provision expressly set out by an order of the Board and these RRT Terms, the Board order shall govern.

2.3 Headings

The division of these RRT Terms into sections, subsections and other subdivisions and the insertion of headings are for convenience of reference only and shall not affect the construction or interpretation of these RRT Terms.

2.4 Extended Meanings

In these RRT Terms, words importing the singular number only shall include the plural and vice versa, words importing the masculine gender shall include the feminine and neuter gender and vice versa and words importing persons shall include individuals, partnerships, associations, trusts, unincorporated organizations and corporations.

2.5 Rates, Charges and Fees

All rates, charges and fees referred to in these RRT Terms are as set out in the Price Schedule.

ARTICLE 3 - REGULATED RATE SERVICE

3.1 Availability

Regulated Rate Service is available to Eligible Customers strictly in accordance with the Regulated Rate Tariff.

3.2 Application for Service

A residential Eligible Customer, who is not receiving Regulated Rate Service from EESI, can apply for Regulated Rate Service at a Site by contacting EESI by telephone or by any other means acceptable to EESI. At its sole discretion, EESI may require any Residential Rate Classification Customer to provide a photo proof of identification. A Small Commercial Customer, who is not receiving Regulated Rate Service from EESI, must complete an application in writing for Regulated Rate Service at a Site.

EESI requires no less than 3 full Business Days prior notice to ensure a timely connection of Regulated Rate Service at a Site. Expedited connection of Regulated Rate Service is available at an additional charge in accordance with the Price Schedule. EESI may declare at any time, that 30 days notice is required to obtain Regulated Rate Service. During any such period, an additional fee will apply in lieu of notice.

If EESI accepts a Customer's application, EESI will open an account for the Customer for Regulated Rate Service at the applied for Site and the Customer shall be the "Customer of Record" for the Site, and will pay EESI a processing charge for opening the account. The Customer will be responsible to pay to EESI all amounts charged to the account from the time the account is opened until it is closed as provided in Sections 3.7 and 3.8.

3.3 Credit Information

EESI may at any time request information:

(a) From a prospective Customer required to determine the Customer's credit history and the credit risk of the Customer; and

(b) From an existing Customer required to determine the Customer's credit history and the credit risk of the Customer when the Customer has paid a bill late more than once in any six month period or when EESI has other reasonable grounds for believing that the existing Customer is a high credit risk, including without limitation, identification, contact and credit information. If a prospective Customer or existing Customer refuses to provide the requested information, then EESI may refuse or discontinue, as the case may be, Regulated Rate Service to the Customer.

3.4 Refusal of Regulated Rate Service

EESI reserves the right to refuse Regulated Rate Service to a Customer at a Site where:

(a) a previous Customer at the Site had a history of non-payment and EESI believes, on reasonable grounds, that the defaulting Customer would continue to occupy the premises located at the Site;

(b) the Customer has not complied with the applicable provisions of the Regulated Rate Tariff to EESI's satisfaction;

(c) the Customer has not provided the deposit required by EESI;

(d) EESI is not satisfied with the Customer's credit rating or credit history, unless the Customer has provided a deposit satisfactory to EESI in accordance with section 3.6;

(e) the Customer has an outstanding balance with EESI for Regulated Rate Service.

3.5 Customer Change of Name or Information

If a Customer has a change of name or contact information, including mailing address and telephone number, for continuation of Regulated Rate Service the Customer must notify EESI of such change as soon as reasonably possible. EESI reserves the right to require that such notification be made in writing.

3.6 Deposits

3.6.1 Requirement for Deposit

EESI, in its sole discretion, may require a deposit or an increase in an existing deposit by a Customer including, without limitation, in the following circumstances:

(a) the Customer has paid a bill late more than once in any six month period;

(b) the Customer has issued more than one cheque that has been returned for non-sufficient funds in any six month period;

(c) there has been more than a 50% increase in the Customer's average monthly consumption of Energy;

(d) the Customer's service was disconnected for non-payment;

(e) upon application by the Customer for re-connection after a cut-off for non-payment; or

(f) the Customer making the application for service has a credit rating which is not satisfactory to EESI.

3.6.2 Waiver of Deposit Requirement

EESI, in its sole discretion, may waive the requirement for a deposit by Customer under Section

3.6.1 including, without limitation, in the following circumstances:

(a) where the Customer has a previous good payment history with EESI;

(b) where a result satisfactory to EESI is obtained from an external credit check;

(c) where the Customer provides a co-signor who agrees to be personally responsible for payment for Energy supplied and services rendered to the Customer and who has a credit rating acceptable to EESI; or

(d) where the Customer provides to EESI an indemnity bond or irrevocable letter of credit from a financial institution satisfactory to EESI.

3.6.3 Maximum Deposit

The maximum deposit EESI will require from a Customer under this Regulated Rate Tariff is equal to 25% of the annual total charge payable by the Customer, as estimated by EESI.

3.6.4 Return of Deposit

A deposit made by a Customer may be returned to the Customer after a satisfactory payment history over a period of 12 consecutive months or when the Customer's Regulated Rate Service is terminated and the Customer's account is closed. Where a Customer's Regulated Rate Service is terminated and the Customer's account is closed for non-payment, prior to any refund, the deposit will be applied to the balance owing by the Customer to EESI.

3.6.5 Interest Payable on Deposits

EESI will pay to a Customer at the end of each calendar year or when the Customer's account is closed, simple interest on the daily balance of any cash deposit held by EESI in respect of the Customer. The interest rate applicable for each year is the "Bank Rate" announced by the Bank of Canada and in effect on January 1 of that year.

3.7 Closing an Account

Subject to Section 3.8, a Customer may close an account for Regulated Rate Service at a Site by giving EESI notice to close the account. In order to close the account on a specified date, EESI requires at least three full Business Days prior notice. EESI will determine whether a final meter reading is required.

3.8 Account Closure on Switch of Retailer

To close an account for Regulated Rate Service at a Site for the purpose of switching to a new Retailer, a Customer must give EESI no less than 60 days prior notice to close the account. Expedited service to close an account for may be obtained on no less than 30 days notice on payment of the following fee for the applicable rate class of service:

Residential	$20.00
Exterior Lighting (per fixture)	$10.00
Commercial	$60.00

3.9 Account and Regulated Rate Service May Not Be Assigned

A Customer cannot assign his account for Regulated Rate Service or any rights in relation to Regulated Rate Service for a Site to a new occupant or owner of the premises at which the Site is located. The new occupant or owner must apply for Regulated Rate Service at the Site. The Customer is responsible for payment for all Regulated Rate Service provided to the Customer up to the time EESI has closed the account and final charges for consumption have been applied.

ARTICLE 4 - MEASUREMENT OF ENERGY CONSUMPTION

4.1 Measurement provided by EPCOR Distribution

EPCOR Distribution provides to EESI under its Distribution Tariff meter readings and estimates of consumption of Energy by Customers. Billings to Customers under these RRT Terms shall be based on those meter readings and estimates. EESI assumes no liability to the Customer for meter readings and estimates provided by EPCOR Distribution.

4.2 Meter Testing

If a Customer believes his meter to be in error, EESI will arrange to have the meter tested by EPCOR Distribution at the request of the Customer and the Customer will pay EESI all charges for meter testing incurred by EESI in accordance with EPCOR Distribution's Distribution Tariff.

ARTICLE 5 - BILLINGS AND PAYMENT

5.1 Billing Practices

EESI performs Regulated Rate Services for Customers on credit and does not require payment in advance, except where a deposit is required in accordance with these RRT Terms.

Charges for Regulated Rate Services are due on the date that a Customer's meter is read, or estimated as the case may be, however, EESI will allow no less than 21 days for payment without credit charge or interest by a payment due date stated on the Customer's bill.

Once a month, EESI will send a Customer bill for Regulated Rate Service provided to the Customer during the previous month, calculated in accordance with the Price Schedule. The bill may be combined with a bill for Non-Regulated Rate Services provided to the Customer by EESI.

5.2 Responsibility to Pay

Each Customer shall pay the full amount of any bill issued to the Customer by EESI by the due date specified on the bill, without prejudice to the Customer's right to contest any rate or fee

charged. A failure to pay any amount billed by EESI shall be a default of payment under these RRT Terms and the Customer shall be subject to EESI's collection policies as outlined in this section 5.2 and to the discontinuance or termination of Regulated Rate Service and disconnection of the Customer's Service Connection(s) as provided under Article 6.

EESI will use the following process prior to disconnection of a Customer's Service Connection(s) for failure by the Customer to pay an amount billed by EESI:

(a) If payment of a bill is not received 30 days subsequent to the due date specified on a bill, EESI will send the Customer a written notice indicating that payment has not been received and that to ensure continuation of service, payment of arrears must be "received" within 7 working days of the date of the written notice.

(b) If the Customer does not contact EESI within 7 working days of the date of the written notice to make arrangements to pay the outstanding bill, EESI will call the Customer. The Customer will be advised that payment arrangements must be made within 4 working days or Service will be disconnected.

(c) If the Customer does not pay the outstanding bill within 4 business days after the warning is provided, EESI may without further notice to the Customer instruct EPCOR Distribution to disconnect the Customer's Service Connection.

If a Customer's account is closed, any outstanding charges may be transferred to any other Regulated Rate Tariff account held by the same person.

5.3 Adjustments to Bills

Bills rendered by EESI under these RRT Terms will include, among other things, charges payable by EESI to EPCOR Distribution for Distribution Access Service arranged by EESI on behalf of Customers under EPCOR Distribution's Distribution Tariff approved by the Regulator. Those charges are or may be subject to adjustment under EPCOR Distribution's Distribution Tariff. Bills rendered by EESI under these RRT Terms may be adjusted from time to time to, among other things, reflect adjustments by EPCOR Distribution under its Distribution Tariff and EESI will issue refunds or credits as appropriate to affected Customers.

5.4 Lost Bills

If a Customer's bill is lost or not received, the Customer should contact EESI to determine the amount owed. Failure to receive a bill does not release a Customer from the obligation to pay the amount owing to EESI under the Regulated Rate Tariff. The late payment charge under Section 5.5 will apply if the bill is not paid by its due date. If a Customer requires a duplicate copy of the bill, a charge may apply.

5.5 Late Payment Charge

If a Customer does not pay a bill for a month in full by the due date specified in the bill, the Customer will be liable to pay to EESI, in addition to the amount of the bill, a late payment charge equal to 2.5% of the amount of the bill that applies to the current billing period. Should

the bill remain outstanding after the due date, EESI may commence collection action. In addition, EESI may require a deposit or an increase in the amount of an existing deposit.

5.6 Partial Payments

Partial payments on an account will be applied to the unpaid amounts (including amounts for Non-Regulated Rate Services) outstanding on the oldest bills. If a payment does not cover the total unpaid amount outstanding on a bill and the bill includes charges for both Regulated Rate Service and Unregulated Service, then the payment will be applied to the unpaid charges for Regulated Rate Service and Unregulated Service, pro rata, on the basis of the respective amounts for those charges.

5.7 Responsibility for Collection Costs

Recovery of any balance on a Customer's bill that has not been paid by the date that payment is due may be referred to a collection agency.

Prudent and reasonable external collection costs incurred by EESI will be added to the Customer's bill.

5.8 Dishonoured Cheque Charge

A Customer will be charged a fee in accordance with the Price Schedule for each cheque dishonoured for non-sufficient funds. A dishonoured cheque may trigger immediate collection action which could lead to disconnection of the Customer's Service Connection(s) as provided under Article 6.

5.9 Other Occupants' Liability for Payment

Where the Customer of Record for a Site has vacated the premises where the Site is located or defaulted on payment of a bill for Regulated Rate Service, other occupants of the premises who continue to receive Regulated Rate Service shall be deemed to be the Customer of Record and shall be liable for payment for Regulated Rate Services provided in accordance with the Regulated Rate Tariff.

ARTICLE 6 - TERMINATION OF REGULATED RATE SERVICE FOR DEFAULT

6.1 Termination of Regulated Rate Service

In the event of a default by the Customer under the Regulated Rate Tariff or any Regulated Rate Service Agreement, EESI may, in its sole discretion and in accordance with Section 5.2, discontinue or terminate Regulated Rate Service to the Customer and require EPCOR Distribution to disconnect the Customer's Service Connection(s) and discontinue Distribution

Access Service to the Customer or otherwise exercise and enforce any other right or remedy EESI may have.

6.2 Restoration of Regulated Rate Service

In the event of discontinuance or termination of Regulated Rate Service or disconnection of a Service Connection(s) of a Customer for non-payment, to have Regulated Rate Service restored, the Customer must pay all outstanding bills in full, provide a deposit to EESI in accordance with Section 3.6 and pay a reconnection fee in accordance with the Price Schedule.

ARTICLE 7 - RESPONSIBILITY AND LIABILITY

7.1 Continuity of Regulated Rate Service

EESI will endeavor at all times to provide regular and uninterrupted Regulated Rate Service to Customers as provided in the Regulated Rate Tariff.

However, if Regulated Rate Service is interrupted, defective, curtailed, reduced, irregular, or fails from causes or circumstances beyond EESI's control, EESI shall not be liable to the Customer or any other Person for the interruption, defect, curtailment, reduction, irregularity or failure.

Without limiting the generality of the foregoing, EESI does not own or operate the Distribution System or any other part of the Alberta Interconnected Electric System and does not guarantee continuous Regulated Rate Service. Under its Distribution Tariff, EPCOR Distribution, among other things, reserves the right to disconnect or otherwise curtail, interrupt or reduce Distribution Access Service to Customers of EESI and to withhold connection or disconnect a Customer's Service Connection in various circumstances with or without notice to EESI or its Customers. EESI is also required to co-operate with EPCOR Distribution regarding operating instructions, policies, and procedures of the System Controller, Transmission Administrator and transmission facility owners which may include such things as reducing supply voltage to Customers and full interruption of Customers' Loads. Further, from time to time, Distribution Access Service and Regulated Rate Service may be interrupted, defective, irregular or fail by reason of actions by EPCOR Distribution, transmission system owners, the Transmission Administrator or the System Controller or conditions on EPCOR Distribution's Distribution System or otherwise on the Alberta Interconnected Electric System. Such actions (including actions by EPCOR Distribution pursuant to its Distribution Tariff) and conditions and compliance by EESI with EPCOR Distribution's Distribution Tariff shall constitute circumstances beyond the control of EESI for which EESI shall not be liable.

7.2 Force Majeure

EESI is relieved of its obligations under its Regulated Rate Tariffs and these RRT Terms, and shall not be liable for any failure to provide Regulated Rate Services to the extent that and when such failure is due to, or is a consequence, any event of Force Majeure.

7.3 Limitation on EESI Liability to Customer

Except for direct physical loss, injury or damage to a Customer or the Customer's property resulting from the negligence or wilful misconduct of EESI or its employees or agents acting within the scope of their employment, EESI shall not be liable to a Customer, whether in tort,

contract, strict liability or otherwise, for any loss, damage, expense, charge, cost or other liability of any kind suffered or incurred by the Customer arising out of or in any way connected with any interruption, defect, irregularity, failure, curtailment or reduction in Regulated Rate Service. For the purpose of this Section 7.3, "direct physical loss, injury or damage" shall not include any loss, injury or damage of an indirect, special, exemplary, punitive or consequential nature including, without limitation, loss of revenues, loss of profits, loss of earnings, loss of contract, loss of opportunity, cost of capital, business interruption, claims of a Customer's customers, contractors and other third parties or any other similar loss, damage, expense, cost or liability whatsoever, whether or not any such loss, damage, expense, cost or liability was foreseeable.

Any claim by a Customer for loss, injury or damage must be filed with EESI within 180 days from the date of occurrence of the incident that is the subject of the claim, failing which EESI shall have no liability to the Customer for any such loss, injury or damage.

7.4 Distribution Tariff

Each Customer shall be obligated for the Service Connection to a Site to permit the Customer to receive Regulated Rate Service. Each Customer is bound by, and shall comply with, all provisions of the Distribution Tariff applicable to the Customer. At the request of EESI, a Customer will enter into an agreement with EPCOR Distribution confirming that the Customer is bound by the applicable provisions of the Distribution Tariff.

Pursuant to these RRT Terms, EESI is the Authorized Customer Representative of a Customer as defined in the Distribution Tariff, and in that capacity EESI is obligated to make payments on behalf of the Customer in respect of the Customer's Distribution Access Service. Accordingly, each Customer shall pay to EESI all Distribution Access Charges that EESI, as the Customer's Authorized Customer Representative, is obligated to pay to EPCOR Distribution under the Distribution Tariff.

In addition to all other remedies available to EESI upon default by the Customer of its obligations provided under these RRT Terms, EESI shall be entitled to request EPCOR Distribution for de-enrollment of service for the Customer in accordance with the Distribution Terms, so that EESI's financial obligation for the Customer is terminated, effective in accordance with the Distribution Terms.

7.5 Indemnification by Customer

Each Customer shall indemnify and hold EESI and its employees and agents harmless from and against any claim for any loss, damage, expense, charge, cost (including legal fees on a solicitor-and-his-own-client basis), fine, penalty or other liability of any kind suffered or incurred by EESI arising out of or in any way connected with any failure by the Customer or the Customer's Facilities to comply with EPCOR Distribution's Distribution Tariff or any legal or regulatory requirement related to Distribution Services.

7.6 EESI Indemnification

EESI shall indemnify and hold a Customer harmless from and against direct physical loss, injury or damage to the Customer or the Customer's property resulting from the negligence or wilful misconduct of EESI or its employees or agents acting within the scope of their employment. For the purpose of this section 7.6, "direct physical loss, injury, or damage" shall not include any loss,

injury or damage of an indirect, special, exemplary, punitive or consequential nature including, without limitation, loss of revenues, loss of profits, loss of earnings, loss of contract, loss of opportunity, cost of capital, business interruption, claims of a Customer's customers, contractors and other third parties or any other similar loss, damage, expense, cost or liability whatsoever, whether or not any such loss, damage, expense, cost or liability was foreseeable.

Any claim by a Customer for indemnity for loss, injury or damage, must be filed with EESI within 180 days from the date of occurrence of the incident that is the subject of the claim, failing which EESAI shall have no obligation to indemnify the Customer for any such loss, injury or damage.

ARTICLE 8 - DISPUTE RESOLUTION

If any dispute between EESI and a Customer shall arise at any time in connection with the Regulated Rate Tariff, EESI and the Customer, acting reasonably and in good faith, shall use their reasonable efforts to resolve the dispute in an amicable manner. If the dispute cannot be otherwise resolved pursuant to this Section 8, a senior representative of EESI and the Customer shall meet to attempt to resolve the dispute. If EESI and a Customer are not able to resolve their dispute in the manner provided in this Section within a reasonable time, EESI and the Customer may enforce in Alberta any rights and remedies they may have in respect of such dispute under any applicable Alberta laws.

ARTICLE 9 - MISCELLANEOUS

9.1 Compliance with Applicable Legal Authorities

EESI and the Customer are subject to, and shall comply with, all existing or future applicable federal, provincial and local laws, all existing or future orders or other actions of the System Controller or of governmental authorities having applicable jurisdiction. EESI will not be required to violate, directly or indirectly, or become a party to a violation of any requirement of the System Controller or any applicable federal, provincial or local statute, regulation, bylaw, rule or order in order to provide Regulated Rate Service to any Customer. EESI's obligation to provide any Regulated Rate Service is subject to the condition that all requisite governmental and regulatory approvals for the provision of the Regulated Rate Service will have been obtained and will be in force during the period of Regulated Rate Service.

9.2 Assignment

The rights of a Customer under the Regulated Rate Tariff or any Regulated Rate Service Agreement are not assignable.

Any assignment in violation of this Section shall be void.

9.3 No Waiver

The failure of EESI to insist on any one or more instances upon strict performance of any provisions of the Regulated Rate Tariff or any Regulated Rate Service Agreement, or to enforce any of its rights hereunder or thereunder, shall not be construed as a waiver of any such

provisions or the relinquishment of any such right or any other right hereunder or thereunder, which shall remain in full force and effect. No term or condition or breach of a term or condition of the Regulated Rate Tariff or any Regulated Rate Service Agreement shall be waived unless the waiver is in writing and duly executed by an authorized officer of EESI.